UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2011

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to
Commission file number 1-10934

ENBRIDGE ENERGY PARTNERS, L.P.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**39-1715850**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification No.)**

1100 Louisiana
Suite 3300
Houston, Texas 77002
(Address of Principal Executive Offices) (Zip Code)

(713) 821-2000
(Registrant's Telephone Number, Including Area Code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer ☒	Accelerated Filer ☐
Non-Accelerated Filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The registrant had 228,268,964 Class A common units outstanding as of October 31, 2011.

ENBRIDGE ENERGY PARTNERS, L.P.

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In this report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean Enbridge Energy Partners, L.P. and its consolidated subsidiaries. We refer to our general partner, Enbridge Energy Company, Inc., as our "General Partner."

This Quarterly Report on Form 10-Q contains forward-looking statements, which are typically identified by words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "project," "strategy," "target," "could," "should" or "will" and similar words or statements, express or implied, suggesting future outcomes or statements regarding an outlook or the negative of those terms. Although we believe that these forward-looking statements are reasonable based on the information available on the dates these statements are made and processes used to prepare the information, these statements are not guarantees of future performance, and we caution you not to place undue reliance on these statements. By their nature, these statements involve a variety of assumptions, unknown risks, uncertainties and other factors, which may cause actual results, levels of activity and performance to differ materially from those expressed or implied by these statements. Material assumptions may include, among others, the expected supply of and demand for crude oil, natural gas and natural gas liquids, or NGLs; prices of crude oil, natural gas and NGLs; inflation and interest rates; operational reliability; and weather.

Our forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, weather, economic conditions, interest rates and commodity prices, including but not limited to, those risks and uncertainties discussed in this Quarterly Report on Form 10-Q and our other reports that we have filed or will file with the Securities and Exchange Commission, or SEC. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and our future course of action depends on the assessment of all information available at the relevant time by those responsible for the management of our operations. Except to the extent required by law, we assume no obligation to publicly update or revise any forward-looking statements made herein whether as a result of new information, future events or otherwise. All subsequent forward-looking *statements, whether written or oral, attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements and, as such, may be updated in our future filings with the SEC. For additional discussion of risks, uncertainties and assumptions, see "Item 1A. Risk Factors" included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010.*

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2011	2010	2011	2010
	(unaudited; in millions, except per unit amounts)			
Operating revenue (Note 10)	$2,372.2	$1,889.3	$7,033.1	$5,567.9
Operating expenses				
Cost of natural gas (Notes 4 and 10)	1,805.4	1,455.6	5,496.2	4,250.2
Environmental costs, net of recoveries (Note 9)	56.1	477.6	44.8	482.1
Oil measurement adjustments (Notes 1 and 12)	(2.8)	(0.2)	(61.5)	(0.2)
Operating and administrative (Notes 1 and 9)	181.3	142.3	516.0	410.1
Power (Note 10)	37.7	36.7	107.2	105.5
Depreciation and amortization (Note 5)	78.9	79.7	256.9	225.2
Impairment charge	—	10.3	—	10.3
	2,156.6	2,202.0	6,359.6	5,483.2
Operating income (loss)	215.6	(312.7)	673.5	84.7
Interest expense (Notes 6 and 10)	78.7	70.1	236.6	199.0
Other income (expense) (Notes 9 and 14)	—	(0.6)	6.0	16.1
Income (loss) before income tax expense	136.9	(383.4)	442.9	(98.2)
Income tax expense (Note 11)	2.1	2.9	5.3	7.5
Net income (loss)	134.8	(386.3)	437.6	(105.7)
Less: Net income attributable to noncontrolling interest (Note 8)	12.2	20.1	41.0	45.3
Net income (loss) attributable to general and limited partner ownership interest in Enbridge Energy Partners, L.P.	$ 122.6	$ (406.4)	$ 396.6	$ (151.0)
Net income (loss) allocable to limited partner interests	$ 95.9	$ (415.2)	$ 322.9	$ (195.7)
Net income (loss) per limited partner unit (basic and diluted) (Note 2)	$ 0.36	$ (1.74)	$ 1.26	$ (0.82)
Weighted average limited partner units outstanding	264.6	238.1	257.6	236.8

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Net income (loss)	$134.8	$(386.3)	$ 437.6	$(105.7)
Other comprehensive loss, net of tax expense (benefit) of $0.4, $(0.5), $0.5, and $(0.2), respectively (Note 10)	(67.0)	(56.0)	(128.1)	(102.4)
Comprehensive income (loss)	67.8	(442.3)	309.5	(208.1)
Less: Comprehensive income attributable to noncontrolling interest (Note 8)	12.2	20.1	41.0	45.3
Comprehensive income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 55.6	$(462.4)	$ 268.5	$(253.4)

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the nine month period ended September 30,	
	2011	2010
	(unaudited; in millions)	
Cash provided by operating activities		
Net income (loss)	$ 437.6	$ (105.7)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization (Note 5)	256.9	225.2
Derivative fair value net gains (Note 10)	(53.9)	(10.7)
Inventory market price adjustments (Note 4)	2.0	3.6
Environmental costs, net of recoveries (Note 9)	94.7	481.5
Impairment charge	—	10.3
Other (Note 16)	12.8	2.2
Changes in operating assets and liabilities, net of acquisitions:		
Receivables, trade and other	(51.9)	7.4
Due from General Partner and affiliates	8.8	(2.5)
Accrued receivables	91.5	(31.4)
Inventory (Note 4)	(11.5)	(82.5)
Current and long-term other assets (Note 10)	(7.7)	(5.1)
Due to General Partner and affiliates (Note 8)	19.1	14.6
Accounts payable and other (Notes 3 and 10)	37.2	23.2
Environmental liabilities (Note 9)	(148.7)	(147.3)
Accrued purchases	(50.0)	(9.2)
Interest payable	19.2	32.8
Property and other taxes payable	15.3	8.4
Settlement of interest rate derivatives (Note 10)	(18.8)	(3.0)
Net cash provided by operating activities	652.6	411.8
Cash used in investing activities		
Additions to property, plant and equipment (Note 5)	(755.8)	(529.1)
Changes in construction payables	132.2	(5.9)
Asset acquisitions	(26.7)	(703.1)
Other	(10.5)	(3.3)
Net cash used in investing activities	(660.8)	(1,241.4)
Cash provided by financing activities		
Net proceeds from unit issuances (Note 7)	557.6	52.2
Distributions to partners (Note 7)	(412.6)	(356.8)
Repayments to General Partner (Note 8)	(12.4)	(330.7)
Net proceeds from issuances of long-term debt (Note 6)	740.7	890.5
Net repayments under credit facility (Note 6)	—	(438.0)
Net commercial paper borrowings (repayments) (Note 6)	(509.8)	594.8
Borrowings from General Partner (Note 8)	7.0	403.7
Contribution from noncontrolling interest (Note 8)	3.3	96.6
Distributions to noncontrolling interest (Note 8)	(61.1)	(17.2)
Other	(5.7)	(2.5)
Net cash provided by financing activities	307.0	892.6
Net increase in cash and cash equivalents	298.8	63.0
Cash and cash equivalents at beginning of year	144.9	143.6
Cash and cash equivalents at end of period	$ 443.7	$ 206.6

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

	September 30, 2011	December 31, 2010
	(unaudited; dollars in millions)	
ASSETS		
Current assets		
Cash and cash equivalents (Note 3)	$ 443.7	$ 144.9
Receivables, trade and other, net of allowance for doubtful accounts of $1.8 in 2011 and 2010 (Note 9)	269.6	171.2
Due from General Partner and affiliates	18.3	27.1
Accrued receivables	591.0	683.7
Inventory (Note 4)	144.2	134.7
Other current assets (Note 10)	48.3	58.3
	1,515.1	1,219.9
Property, plant and equipment, net (Notes 5 and 14)	9,173.6	8,641.6
Goodwill	246.7	246.7
Intangibles, net	267.9	276.4
Other assets, net (Note 10)	119.3	56.4
	$11,322.6	$10,441.0
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Due to General Partner and affiliates	$ 70.1	$ 53.3
Accounts payable and other (Notes 3 and 10)	427.9	289.2
Environmental liabilities (Note 9)	207.4	227.0
Accrued purchases	554.8	596.4
Interest payable	79.5	60.3
Property and other taxes payable	64.4	49.1
Note payable to General Partner (Note 8)	12.0	11.6
Current maturities of long-term debt (Note 6)	31.0	31.0
	1,447.1	1,317.9
Long-term debt (Note 6)	5,015.9	4,778.9
Note payable to General Partner (Note 8)	330.0	335.8
Other long-term liabilities (Notes 9 and 10)	245.8	122.9
	7,038.8	6,555.5
Commitments and contingencies (Note 9)		
Partners' capital (Notes 7 and 8)		
Class A common units (228,268,964 and 209,084,106 at September 30, 2011 and December 31, 2010 respectively)	3,076.5	2,641.0
Class B common units (7,825,500 at September 30, 2011 and December 31, 2010)	74.7	64.9
i-units (37,053,946 and 35,285,422 at September 30, 2011 and December 31, 2010, respectively)	658.0	579.1
General Partner	275.8	256.8
Accumulated other comprehensive income (loss) (Note 10)	(249.8)	(121.7)
Total Enbridge Energy Partners, L.P. partners' capital	3,835.2	3,420.1
Noncontrolling interest (Note 8)	448.6	465.4
Total partners' capital	4,283.8	3,885.5
	$11,322.6	$10,441.0

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE ENERGY PARTNERS, L.P.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP, for interim consolidated financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all the information and footnotes required by accounting principles generally accepted in the United States of America for complete consolidated financial statements. In the opinion of management, they contain all adjustments, consisting only of normal recurring adjustments, which management considers necessary to present fairly our financial position as of September 30, 2011, our results of operations for the three and nine month periods ended September 30, 2011 and 2010 and our cash flows for the nine month periods ended September 30, 2011 and 2010. We derived our consolidated statement of financial position as of December 31, 2010 from the audited financial statements included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010. Our results of operations for the three and nine month periods ended September 30, 2011 should not be taken as indicative of the results to be expected for the full year due to seasonal fluctuations in the supply of and demand for crude oil, seasonality of portions of our Natural Gas business, timing and completion of our construction projects, maintenance activities, the impact of forward commodity prices and differentials on derivative financial instruments that are accounted for at fair value and the effect of environmental costs and related insurance recoveries on our Lakehead system. Our interim consolidated financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010.

Comparative Amounts

We have made reclassifications to the amounts reported in our consolidated statements of income of $0.2 million for oil measurement gains from "Operating and administrative" to "Oil measurement adjustments" for both the three and nine month periods ended September 30, 2010.

2. NET INCOME PER LIMITED PARTNER AND GENERAL PARTNER INTEREST

In February 2011, the board of directors of Enbridge Energy Management, L.L.C., or Enbridge Management, as delegate of our General Partner, approved a split of our units, which was effected by a distribution on April 21, 2011 of one common unit for each common unit outstanding and one i-unit for each i-unit outstanding to unit holders of record on April 7, 2011. As a result of this unit split, we have retrospectively restated the computation of our "Net income per limited partner unit (basic and diluted)" in the table below and restated the number of units in our consolidated statement of financial position to present the prior year amounts on a split-adjusted basis. Additionally, the formula for distributing available cash among our General Partner and limited partners was revised to reflect this unit split, as set forth in our partnership agreement, as amended, and is presented below.

Distribution Targets	Portion of Quarterly Distribution Per Unit	Percentage Distributed to General Partner	Percentage Distributed to Limited partners
Minimum Quarterly Distribution	Up to $0.295	2%	98%
First Target Distribution	> $0.295 to $0.35	15%	85%
Second Target Distribution	> $0.35 to $0.495	25%	75%
Over Second Target Distribution	In excess of $0.495	50%	50%

We allocate our net income among our General Partner and limited partners using the two-class method in accordance with applicable authoritative accounting guidance. Under the two-class method, we allocate our net income, including any incentive distribution rights, or IDRs, embedded in the general partner interest, to our

General Partner and our limited partners according to the distribution formula for available cash as set forth in our partnership agreement. We also allocate any earnings in excess of distributions to our General Partner and limited partners utilizing the distribution formula for available cash specified in our partnership agreement. We allocate any distributions in excess of earnings for the period to our General Partner and limited partners based on their sharing of losses of 2 percent and 98 percent, respectively, as set forth in our partnership agreement.

We determined basic and diluted net income (loss) per limited partner unit as follows:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2011	2010	2011	2010
	(in millions, except per unit amounts)			
Net income (loss)	$ 134.8	$(386.3)	$ 437.6	$(105.7)
Less: Net income (loss) attributable to noncontrolling interest	12.2	20.1	41.0	45.3
Net income (loss) attributable to general and limited partner interests in Enbridge Energy Partners, L.P.	122.6	(406.4)	396.6	(151.0)
Less distributions paid:				
Incentive distributions to our General Partner	(24.7)	(17.3)	(67.1)	(48.7)
Distributed earnings allocated to our General Partner	(3.0)	(2.5)	(8.5)	(7.4)
Total distributed earnings to our General Partner	(27.7)	(19.8)	(75.6)	(56.1)
Total distributed earnings to our limited partners	(145.5)	(123.2)	(416.8)	(363.5)
Total distributed earnings	(173.2)	(143.0)	(492.4)	(419.6)
Overdistributed earnings	$ (50.6)	$(549.4)	$ (95.8)	$(570.6)
Weighted average limited partner units outstanding	264.6	238.1	257.6	236.8
Basic and diluted earnings per unit:				
Distributed earnings per limited partner unit(1)	$ 0.55	$ 0.52	$ 1.62	$ 1.54
Overdistributed earnings per limited partner unit(2)	(0.19)	(2.26)	(0.36)	(2.36)
Net income (loss) per limited partner unit (basic and diluted)	$ 0.36	$ (1.74)	$ 1.26	$ (0.82)

(1) Represents the total distributed earnings to limited partners divided by the weighted average number of limited partner interests outstanding for the period.

(2) Represents the limited partners' share (98 percent) of distributions in excess of earnings divided by the weighted average number of limited partner interests outstanding for the period and under distributed earnings allocated to the limited partners based on the distribution waterfall that is outlined in our partnership agreement.

3. CASH AND CASH EQUIVALENTS

We extinguish liabilities when a creditor has relieved us of our obligation, which occurs when our financial institution honors a check that the creditor has presented for payment. Accordingly, obligations for which we have made payments that have not yet been presented to the financial institution totaling approximately $29.6 million at September 30, 2011 and $28.9 million at December 31, 2010 are included in "Accounts payable and other" on our consolidated statements of financial position.

4. INVENTORY

	September 30, 2011	December 31, 2010
	(in millions)	
Materials and supplies	$ 2.1	$ 6.3
Crude oil inventory	9.9	8.1
Natural gas and NGL inventory	132.2	120.3
	$144.2	$134.7

The "Cost of natural gas" on our consolidated statements of income includes charges totaling $1.8 million and $2.0 million for the three and nine month periods ended September 30, 2011, respectively, that we recorded to reduce the cost basis of our inventory of natural gas and natural gas liquids, or NGLs, to reflect the current market value. Similar charges of $1.0 million and $3.6 million were recorded to reduce our natural gas and NGLs inventories for the three and nine month periods ended September 30, 2010.

5. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment is comprised of the following:

	September 30, 2011	December 31, 2010
	(in millions)	
Land	$ 36.2	$ 35.7
Rights-of-way	523.5	510.9
Pipelines	6,013.1	5,981.6
Pumping equipment, buildings and tanks	1,423.5	1,306.9
Compressors, meters and other operating equipment	1,509.6	1,477.8
Vehicles, office furniture and equipment	208.5	201.6
Processing and treating plants	448.1	438.3
Construction in progress	966.8	401.9
Total property, plant and equipment	11,129.3	10,354.7
Accumulated depreciation	(1,955.7)	(1,713.1)
Property, plant and equipment, net	$ 9,173.6	$ 8,641.6

Based on our own internal study, with consideration of a third-party consultant's report, revised depreciation rates for our Anadarko, North Texas and East Texas natural gas systems were implemented effective July 1, 2011. The average remaining service life of these natural gas systems was extended from 29 years to 36 years. The predominant factor contributing to the change in service lives was an increase in the estimated remaining reserves in the regions our natural gas systems serve, due to enhancements in fracturing technologies which will allow producers to have greater access to unconventional gas. The new remaining service lives will result in an approximately $34 million annual reduction in depreciation expense in future years, with a reduction of $8.5 million for the current quarter ended September 30, 2011.

6. DEBT

Credit Facility

In September 2011, we entered into a new credit agreement with Bank of America, as administrative agent, and the lenders party thereto, which we refer to as the New Credit Facility. The new agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, $2 billion, a letter of credit subfacility and a swing line subfacility with a maturity date of September 26, 2016.

The New Credit Facility replaces the previously existing credit facilities of $1,167.5 million and $600 million with Bank of America and Royal Bank of Canada, respectively.

Effective September 30, 2011, our New Credit Facility was amended to further modify the definition of Consolidated Earnings Before Income Taxes Depreciation and Amortization, or Consolidated EBITDA, as set forth in the terms of our New Credit Facility, to increase from $550 million to $650 million, the aggregate amount of the costs associated with the crude oil releases on Lines 6A and 6B that are excluded from the computation of Consolidated EBITDA. Specifically, the costs allowed to be excluded from Consolidated EBITDA are those for emergency response, environmental remediation, cleanup activities, costs to repair the pipelines, inspection costs, potential claims by third parties and lost revenue. At September 30, 2011 we were in compliance with the terms of our financial covenants.

The amounts we may borrow under the terms of our New Credit Facility are reduced by the face amount of our letters of credit outstanding. Our current policy is to maintain availability at any time under our New Credit Facility amounts that are at least equal to the amount of commercial paper that we have outstanding at such time. Taking that policy into account, at September 30, 2011, we could borrow $1,500.5 million under the terms of our New Credit Facility, determined as follows:

	(in millions)
Total credit available under New Credit Facility	$2,000.0
Less: Amounts outstanding under New Credit Facility	—
Principal amount of commercial paper outstanding	375.0
Letters of credit outstanding	124.5
Total amount we could borrow at September 30, 2011	$1,500.5

Individual London Inter-Bank Offered Rate, or LIBOR rate, borrowings under the terms of our New Credit Facility may be renewed as LIBOR rate borrowings or as base rate borrowings at the end of each LIBOR rate interest period, which is typically a period of three months or less. These renewals do not constitute new borrowings under the New Credit Facility and do not require any cash repayments or prepayments. For the nine month period ended September 30, 2010, we renewed LIBOR rate borrowings of $915.0 million, on a non-cash basis.

Commercial Paper

We have a commercial paper program that provides for the issuance of up to an aggregate principal amount of $1.5 billion of commercial paper that is supported by our New Credit Facility. Our commercial paper program was increased from $1.0 billion in August 2011. We access the commercial paper market primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the available interest rates we can obtain are lower than the rates available under our New Credit Facility. At September 30, 2011, we had $375.0 million of commercial paper outstanding at a weighted average interest rate of 0.40%, excluding the effect of our interest rate hedging activities. At December 31, 2010, we had $884.9 of commercial paper outstanding at a weighted average interest rate of 0.44%, excluding the effect of our interest rate hedging activities. Our policy is that the commercial paper we can issue is limited by the amounts available under our New Credit Facility.

We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis through borrowings under our New Credit Facility. Accordingly, such amounts have been classified as "Long-term debt" in our accompanying consolidated statements of financial position.

Senior Notes due 2021 and 2040

In September 2011, we issued and sold $600 million in aggregate principal amount of senior notes due 2021, which we refer to as the 2021 Notes. The 2021 Notes bear interest at the rate of 4.20% per year and will mature on September 15, 2021. Interest on the 2021 Notes is payable on March 15 and September 15 of each year, beginning on March 15, 2012.

Also in September 2011, we issued and sold an additional $150 million in aggregate principal amount of our 5.50% notes due in 2040, which we refer to as the 2040 Notes. The additional 2040 Notes will be fully fungible with, rank equally in right of payment with and form a part of the same series as the existing 2040 Notes, originally issued by us in September 2010, for all purposes under the governing indenture.

We received net proceeds from the note offerings in September 2011 of approximately $740.7 million after payment of underwriting discounts and commissions and our estimated offering expenses. We used the net proceeds from these offerings to repay a portion of our outstanding commercial paper, to fund a portion of our capital expansion projects and for general corporate purposes.

Senior Notes due 2019

The holders of our $500 million in aggregate principal amount, 9.875% senior notes due 2019 have an option to require us to repurchase all or a portion of the notes on March 1, 2012 at a purchase price of 100 percent of the principal amount of the notes tendered plus accrued and unpaid interest. If the holders of these senior notes require us to repay the notes on March 1, 2012, we have the ability and intent to finance them on a long-term basis through borrowings under our New Credit Facility. Accordingly, such amounts have been classified as "Long-term debt" in our accompanying consolidated statements of financial position.

Fair Value of Debt Obligations

The table below presents the carrying amounts and approximate fair values of our debt obligations. The carrying amounts of our outstanding commercial paper and borrowings under our New Credit Facility and prior credit facilities approximate their fair values at September 30, 2011 and December 31, 2010, respectively, due to the short-term nature and frequent repricing of these obligations. The fair value of our outstanding commercial paper, borrowings under our New Credit Facility and our prior credit facilities and our Senior Notes due 2019 are included with our long-term debt obligations below since we have the ability to refinance the amounts on a long-term basis. The approximate fair values of our long-term debt obligations are determined using a standard methodology that incorporates pricing points that are obtained from independent, third-party investment dealers who actively make markets in our debt securities. We use these pricing points to calculate the present value of the principal obligation to be repaid at maturity and all future interest payment obligations for any debt outstanding.

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Commercial Paper	$ 375.0	$ 375.0	$ 884.9	$ 884.9
9.150% First Mortgage Notes	31.0	31.6	31.0	33.5
7.900% Senior Notes due 2012	100.0	107.7	100.0	112.1
4.750% Senior Notes due 2013	199.9	209.6	199.9	214.4
5.350% Senior Notes due 2014	200.0	215.2	200.0	221.8
5.875% Senior Notes due 2016	299.9	333.9	299.8	338.1
7.000% Senior Notes due 2018	99.9	117.9	99.9	119.2
6.500% Senior Notes due 2018	398.6	459.5	398.5	463.0
9.875% Senior Notes due 2019	500.0	684.6	499.9	699.1
5.200% Senior Notes due 2020	499.8	529.6	499.8	526.6
4.200% Senior Notes due 2021	597.6	577.8	—	—
7.125% Senior Notes due 2028	99.8	122.2	99.8	121.7
5.950% Senior Notes due 2033	199.7	210.9	199.7	209.0
6.300% Senior Notes due 2034	99.8	109.0	99.8	108.2
7.500% Senior Notes due 2038	399.0	495.4	398.9	493.0
5.500% Senior Notes due 2040	547.3	514.8	398.5	371.6
8.050% Junior subordinated notes due 2067	399.6	407.9	399.5	408.5
Total	$5,046.9	$5,502.6	$4,809.9	$5,324.7

7. PARTNERS' CAPITAL

Split of Partnership Units

Effective April 21, 2011, the board of directors of Enbridge Management, as delegate of our General Partner, approved a two-for-one split of our common units and i-units outstanding to unit holders of record on April 7, 2011. The net income per share and weighted average shares outstanding for the three and nine month periods ended September 30, 2010 presented in our consolidated statements of income and the number of units presented in our consolidated statements of financial position are presented reflecting the retroactive effects of the share split.

Distribution to Partners

The following table sets forth our distributions, as approved by the board of directors of Enbridge Management, during the nine month period ended September 30, 2011.

Distribution Declaration Date	Record Date	Distribution Payment Date	Distribution per Unit[(1)]	Cash available for distribution	Amount of Distribution of i-units to i-unit Holders[(2)]	Retained from General Partner[(3)]	Distribution of Cash
		(in millions, except per unit amounts)					
January 28, 2011	February 4, 2011	February 14, 2011	$0.51375	$150.5	$18.1	$0.4	$132.0
April 28, 2011	May 6, 2011	May 13, 2011	$0.51375	$152.0	$18.4	$0.4	$133.2
July 28, 2011	August 5, 2011	August 12, 2011	$0.53250	$167.2	$19.4	$0.4	$147.4

(1) Distributions per unit for the distribution paid on February 14, 2011 are presented retrospectively applying the two-for-one split of our units.

(2) We issued 1,768,523 split adjusted i-units to Enbridge Management, the sole owner of our i-units, during 2011 in lieu of cash distributions.

(3) We retained an amount equal to two percent of the i-unit distribution from our General Partner to maintain its two percent general partner interest in us.

Changes in Partners' Capital

The following table presents significant changes in partners' capital accounts attributable to our General Partner and limited partners as well as the noncontrolling interest in our consolidated subsidiary, Enbridge Energy, Limited Partnership, or the OLP, for the three and nine month periods ended September 30, 2011 and 2010. The noncontrolling interest in the OLP arises from the joint funding arrangement with our General Partner and its affiliate to finance construction of the United States portion of the Alberta Clipper crude oil pipeline and related facilities, which we refer to as the Alberta Clipper Pipeline.

	For the three month periods ended September 30,		For the nine month periods ended September 30,	
	2011	2010	2011	2010
	(in millions)			
General and limited partner interests				
Beginning balance	$3,626.6	$3,842.8	$3,541.8	$3,803.4
Proceeds from issuance of partnership interests, net of costs	483.2	37.1	559.2	52.2
Capital contribution	—	1.8	—	3.7
Net income (loss)	122.6	(406.4)	396.6	(151.0)
Distributions	(147.4)	(123.8)	(412.6)	(356.8)
Ending balance	$4,085.0	$3,351.5	$4,085.0	$3,351.5
Accumulated other comprehensive income (loss)				
Beginning balance	$ (182.8)	$ (121.0)	$ (121.7)	$ (74.6)
Net realized losses on changes in fair value of derivative financial instruments reclassified to earnings	22.4	3.6	68.5	22.5
Unrealized net loss on derivative financial instruments	(89.4)	(59.6)	(196.6)	(124.9)
Ending balance	$ (249.8)	$ (177.0)	$ (249.8)	$ (177.0)
Noncontrolling interest				
Beginning balance	$ 454.1	$ 453.3	$ 465.4	$ 341.1
Capital contributions	—	9.6	3.3	96.6
Comprehensive income:				
Net income	12.2	20.1	41.0	45.3
Distributions to noncontrolling interest	(17.7)	(17.2)	(61.1)	(17.2)
Ending balance	$ 448.6	$ 465.8	$ 448.6	$ 465.8
Total partners' capital at end of period	$4,283.8	$3,640.3	$4,283.8	$3,640.3

Equity Distribution Agreement

In June 2010, we entered into an Equity Distribution Agreement, or EDA, for the issuance and sale from time to time of our Class A common units up to an aggregate amount of $150.0 million. The EDA allowed us to issue and sell our Class A common units at prices we deemed appropriate for our Class A common units. Under the EDA, we sold 2,118,025 Class A common units, representing 4,236,050 units after giving effect to a two-for-one split of our Class A common units that became effective on April 21, 2011, for aggregate gross proceeds of $124.8 million, of which $64.5 million are gross proceeds received in 2011. No further sales will be made under that agreement. On May 27, 2011, we de-registered the remaining aggregate $25.2 million of Class A common units that were registered for sale under the EDA and remained unsold as of that date.

On May 27, 2011, the Partnership entered into an Amended and Restated Equity Distribution Agreement, or Amended EDA, for the issuance and sale from time to time of our Class A common units up to an aggregate amount of $500.0 million from the execution date of the agreement through May 20, 2014. The units issued under the Amended EDA are in addition to the units offered and sold under the EDA. The issuance and sale of our Class A common units, pursuant to the Amended EDA, may be conducted on any day that is a trading day for the New York Stock Exchange.

The following table presents the net proceeds from our Class A common unit issuances, pursuant to the Amended EDA, during the nine month period ended September 30, 2011:

Issuance Date	Number of Class A common units Issued	Average Offering Price per Class A common unit	Net Proceeds to the Partnership[1]	General Partner Contribution[2]	Net Proceeds Including General Partner Contribution
		(unaudited; in millions, except units and per unit amounts)			
May 27 to June 30, 2011	333,794	$30.30	$ 9.9	$0.2	$10.1
July 1 to September 30, 2011	751,766	28.38	20.8	0.4	21.2
	1,085,560		$30.7	$0.6	$31.3

(1) Net of commissions and issuance costs of $0.4 million and $0.6 million for the three and nine month periods ended September 30, 2011.

(2) Contributions made by the General Partner to maintain its two percent general partner interest.

Issuance of Class A Common Units

The following table presents the net proceeds from our Class A common unit issuances for the current year other than pursuant to the EDA and the Amended EDA described above. The proceeds from the September 2011 offering will be used to fund a portion of our capital expansion projects, while the proceeds from the July offering were used to repay a portion of our outstanding commercial paper.

2011 Issuance Date	Number of Class A common units Issued	Offering Price per Class A common unit	Net Proceeds to the Partnership[1]	General Partner Contribution[2]	Net Proceeds Including General Partner Contribution
		(in millions, except units and per unit amount)			
September	8,000,000	$28.20	$218.3	$4.6	$222.9
July	8,050,000	$30.00	$233.7	$4.9	$238.6
2011 Totals	16,050,000		$452.0	$9.5	$461.5

(1) Net of underwriters' fees and discounts, commissions and issuance expenses if any.

(2) Contributions made by the General Partner to maintain its two percent general partner interest.

8. RELATED PARTY TRANSACTIONS

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge Inc., or Enbridge. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010. In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement, a credit agreement between our General Partner and us to finance the Alberta Clipper Pipeline, by issuing a promissory note payable to our General Partner, at which time we also terminated the A1 Credit Agreement. The promissory note payable, which we refer to as the A1 Term Note, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our 5.20% senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline and is subordinate to all of our senior indebtedness. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the Alberta Clipper Pipeline that our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement for any additional costs associated with our construction of the Alberta Clipper Pipeline that we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. Pursuant to the terms of the A1 Term Note, we are required to make semi-annual payments of principal and accrued interest. The semi-annual principal payments are based upon a straight-line amortization of the principal balance over a 30 year period as set forth in the approved terms of the cost of service recovery model associated with the Alberta Clipper Pipeline. The approved terms for the Alberta Clipper Pipeline are described in the "Alberta Clipper United States Term Sheet," which is included as Exhibit I to the June 27, 2008 Offer of Settlement filed with the Federal Energy Regulatory Commission, or FERC, by the OLP and approved on August 28, 2008 (Docket No. OR08-12-000).

A summary of the cash activity for the A1 Term Note for the nine month periods ended September 30, 2011 and 2010 are as follows:

	A1 Term Note September 30,	
	2011	2010
	(in millions)	
Beginning Balance	$347.4	$ —
Borrowings	7.0	348.8
Repayments	(12.4)	(6.1)
Ending Balance	$342.0	$342.7

Our General Partner also made equity contributions totaling $3.3 million and $96.6 million to the OLP during the nine month periods ended September 30, 2011 and 2010, respectively, to fund its equity portion of the construction costs associated with the Alberta Clipper Pipeline.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amounts of $12.2 million and $41.0 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Pipeline for the three and nine month periods ended September 30, 2011, respectively. We allocated $20.1 million and $45.3 million for the same three and nine month periods ended September 30, 2010, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Distribution to Series AC Interests

The following table presents distributions paid by the OLP to our General Partner and its affiliate during the nine month period ended September 30, 2011, representing the noncontrolling interest in the Series AC and to us, as the holders of the Series AC general and limited partner interests. The distributions were declared by the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC interests.

Distribution Declaration Date	Distribution Payment Date	Amount Paid to Partnership	Amount paid to the noncontrolling interest	Total Series AC Distribution
	(in millions)			
January 28, 2011	February 14, 2011	$10.9	$21.8	$32.7
April 28, 2011	May 13, 2011	10.8	21.6	32.4
July 28, 2011	August 12, 2011	8.8	17.7	26.5
		$30.5	$61.1	$91.6

9. COMMITMENTS AND CONTINGENCIES

Environmental Liabilities

We are subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid hydrocarbon and natural gas pipeline operations, and we could, at times, be subject to environmental cleanup and enforcement actions. We manage this environmental risk through appropriate environmental policies and practices to minimize any impact our operations may have on the environment. To the extent that we are unable to recover environmental liabilities through insurance or other potentially responsible parties, we will be responsible for payment of liabilities arising from environmental incidents associated with the operating activities of our Liquids and Natural Gas businesses. Our General Partner has agreed to indemnify us from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer of these assets to us in 1991. This excludes any liabilities resulting from a change in laws after such transfer. We continue to voluntarily investigate past leak sites on our systems for the purpose of assessing whether any remediation is required in light of current regulations.

As of September 30, 2011 and December 31, 2010, we have $47.2 million and $44.2 million, respectively, included in "Other long-term liabilities," that we have accrued for costs we have incurred primarily to address remediation of contaminated sites, asbestos containing materials, management of hazardous waste material disposal, outstanding air quality measures for certain of our liquids and natural gas assets and penalties we have been or expect to be assessed.

Lakehead Lines 6A & 6B Crude Oil Releases

Line 6B Crude Oil Release

As a result of our response to recent additional work direction from the Environmental Protection Agency, or EPA, additional information concerning the reassessment of the overall monitoring area, related cleanup, including submerged oil recovery operations, and remediation activities, we have revised our total estimate for costs related to the crude oil release on Line 6B of our Lakehead system to $725.0 million, before insurance recoveries, as of September 30, 2011, an increase of $140.0 million from June 30, 2011, as we have previously disclosed. The $140.0 million increase in our estimate includes the estimated costs related to the additional scope of work set forth in our response to the EPA directive we submitted to the EPA on October 20, 2011. We continue to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. We expect to make payments for additional costs associated with reassessment, remediation and restoration of the area and air and groundwater monitoring, along with other legal, professional and regulatory costs through future periods. All the initiatives we will undertake in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at September 30, 2011. Our estimates do not include amounts we have capitalized or any fines, penalties or claims associated with the release that may later become evident and is before insurance recoveries. Our assumptions include, where applicable, estimates of the expected number of days the associated services will be required and rates that we have obtained from contracts negotiated for the respective service and equipment providers. As we receive invoices for the actual personnel, equipment and services, our estimates will continue to be further refined. Our estimates also consider currently available facts, existing technology and presently enacted laws and regulations. These amounts also consider our and other companies' prior experience remediating contaminated sites and data released by government organizations. Despite the efforts we have made to ensure the reasonableness of our estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. We continue to have the potential of incurring additional costs in connection with this crude oil release due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

The material components underlying our total estimated loss for the cleanup, remediation and restoration associated with the Line 6B crude oil release include the following:

	(in millions)
Response Personnel & Equipment	$274
Environmental Consultants	132
Professional, regulatory and other	319
Total	$725

We expect that we will have paid approximately 80 to 90 percent of the estimated costs associated with this crude oil release by the end of 2011. We have made payments totaling $479.5 million for costs associated with the Line 6B crude oil release, $185.9 million of which relates to the nine month period ended September 30, 2011. We have a remaining liability of $245.5 million, a majority of which is presented as current, on our consolidated statement of financial position at September 30, 2011. Additionally, we recognized $85.0 million and $135.0 million of insurance recoveries in our consolidated statements of income for the three and nine month periods ended September 30, 2011.

Line 6A Crude Oil Release

We are continuing to monitor the areas affected by the crude oil release from Line 6A of our Lakehead system for any additional requirements. We have substantially completed the cleanup, remediation and restoration of the areas affected by the release.

In connection with this crude oil release, we have not revised our estimate since June 30, 2011 that we will incur aggregate costs of approximately $48.0 million, before insurance recoveries and excluding fines and penalties. We continue to monitor this estimate based upon actual invoices received and paid for the personnel, equipment and services provided by our vendors and currently available facts specific to these circumstances, existing technology and presently enacted laws and regulations to determine if our estimate should be updated. We have made payments totaling $45.0 million for costs associated with the Line 6A crude oil release, $10.6 million of which relates to the nine month period ended September 30, 2011. We have a remaining total liability of $3.0 million, a majority of which is presented as current, on our consolidated statement of financial position as of September 30, 2011.

We have the potential of incurring additional costs in connection with this crude oil release, including fines and penalties as well as expenditures associated with litigation. We are also pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

Lines 6A & 6B Fines and Penalties

Our estimated environmental costs for both the Line 6A and Line 6B crude oil releases do not include an estimate for fines and penalties at September 30, 2011, which may be imposed by the EPA and Pipeline and Hazardous Materials Safety Administration, or PHMSA, in addition to other state and local governmental agencies. Several factors remain outstanding at the end of the period that we consider critical in estimating the amount of fines and penalties that we may be assessed.

Due to the absence of sufficient information, we cannot provide a reasonable estimate of our liability for fines and penalties that we could be assessed in connection with each of the releases. As a result, we have not recorded any liability for expected fines and penalties.

Insurance Recoveries

We are included in the comprehensive insurance program that is maintained by Enbridge for its subsidiaries and affiliates, which renews May of each year. The program includes commercial liability insurance coverage that is consistent with coverage considered customary for our industry and includes coverage for environmental incidents such as those we have incurred for the crude oil releases from Lines 6A and 6B, excluding costs for fines and penalties. The claims for the crude oil release for Line 6B are covered by the insurance policy that expired on April 30, 2011, which had an aggregate limit of $650.0 million for pollution liability. Based on our increased estimate of costs associated with these crude oil releases, Enbridge and its affiliates, including us, are likely to exceed the limits of its coverage under this insurance policy. We are pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained. Additionally, fines and penalties would not be covered under our existing insurance policy.

We recognized $85.0 million and $135.0 million of insurance recoveries as reductions to "Environmental costs, net of recoveries" in our consolidated statements of income for the three and nine month periods ended September 30, 2011, respectively. At September 30, 2011, we have $85.0 million recorded in "Receivables, trade and other" in our consolidated statement of financial position for an insurance payment we will receive for a claim we filed in connection with the Line 6B crude oil release. In the third quarter of 2011, we received insurance payments of $15.0 million for claims we filed. We expect to record a receivable for additional amounts we claim for recovery pursuant to our insurance policies during the period that we deem realization of the claim for recovery to be probable.

During the second quarter of 2011, Enbridge renewed its comprehensive insurance program and the current coverage year has an aggregate limit of $575.0 million for pollution liability for the period May 1, 2011 through April 30, 2012.

Line 6B Pipeline Integrity Plan

In connection with the restart of Line 6B of our Lakehead system, we committed to accelerate a process we had initiated prior to the crude oil release to perform additional inspections, testing and refurbishment of Line 6B within and beyond the immediate area of the July 26, 2010 crude oil release. Pursuant to this agreement with PHMSA, we completed remediation of those pipeline anomalies identified by us between the years 2007 and 2009 that were scheduled for refurbishment and anomalies identified for action in a July 2010 PHMSA notification on schedule, within 180 days of the September 27, 2010 restart of Line 6B, as required. In addition to the required integrity measures, we also agreed to replace a 3,600 foot section of the Line 6B pipeline that lies underneath the St. Clair River in Michigan within one year of the restart of Line 6B, subject to obtaining required permits. A new line was installed beneath the St. Clair River in March 2011 and was tied into Line 6B during June 2011.

In February 2011, we filed a supplement to our Facilities Surcharge Mechanism, or FSM, which became effective on April 1, 2011 when it was approved by the FERC for recovery of $175.0 million of capital costs and $5.0 million of operating costs for the 2010 and 2011 Line 6B Pipeline Integrity Plan. The costs associated with the Line 6B Pipeline Integrity Plan, which include an equity return component, interest expense and an allowance for income taxes, will be recovered over a 30-year period, while operating costs will be recovered through our annual tolls for actual costs incurred. These costs include costs associated with the PHMSA Corrective Action Order and other required integrity work.

Line Replacement Program

On May 12, 2011, we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system at an estimated cost of $286 million. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory approvals, the new segments of pipeline will be constructed mostly in 2012 and are targeted to be placed in-service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through our FSM that is part of the system-wide rates of the Lakehead system. We have subsequently revised the scope of this project to increase the cost by approximately $30 million, which will bring the total capital for this replacement program to an estimated cost of $316 million. The $30 million of additional costs do not currently have recovery under our FSM.

The total cost of these integrity measures is separate from the environmental liabilities discussed above. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with our capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature.

Proceeds from Claim Settlements

We received proceeds of $11.6 million for settlement of claims we made for payment from unrelated parties in connection with operational matters that occurred in the normal course of business. We recorded $5.6 million as a reduction to "Operating and administrative" expenses of our Liquids segment and $6.0 million as "Other income" in our consolidated statements of income for the nine month period ended September 30, 2011 for the amounts we received in April 2011.

Legal and Regulatory Proceedings

We are a participant in various legal and regulatory proceedings arising in the ordinary course of business. Some of these proceedings are covered, in whole or in part, by insurance. We are also directly, or indirectly, subject to challenges by special interest groups to regulatory approvals and permits for certain of our expansion projects.

We paid $100,000 to PHMSA in October 2011 to resolve an administrative civil penalty brought against us by PHMSA for failure to follow our procedures for maintaining minimum clearance from underground facilities when excavating with powered equipment, related to one of our pipelines located in Rusk County, Wisconsin.

A number of governmental agencies and regulators have initiated investigations into the Line 6A and Line 6B crude oil releases. Approximately twenty-five actions or claims have been filed against us and our affiliates, in state and federal courts in connection with the Line 6B crude oil release, including direct actions and actions seeking class status. With respect to the Line 6B crude oil release, no penalties or fines have been assessed against us as of September 30, 2011.

Governmental agencies and regulators have also initiated investigations into the Line 6A crude oil release. One claim has been filed against us and our affiliates by the State of Illinois in state court in connection with this crude oil release, and the parties are currently operating under an agreed interim order. The costs associated with this order are included in the estimated environmental costs accrued for the Line 6A crude oil release. We are also pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained.

We have accrued a provision for future legal costs associated with the Line 6A and Line 6B crude oil releases as described above in the section titled *Lakehead Lines 6A & 6B Crude Oil Releases* of this footnote.

10. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate, crude oil and fractionation margins. Fractionation margins represent the relative difference between the price we receive from NGL sales and the corresponding cost of natural gas we purchase for processing. Our interest rate risk exposure results from changes in interest rates on our variable rate debt and exists at the corporate level where our variable rate debt obligations are issued. Our exposure to commodity price risk exists within each of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in interest rates and commodity prices, as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices. We have hedged a portion of our exposure to variability in future cash flows associated with the risks discussed above through 2016 in accordance with our risk management policies.

We record all derivative financial instruments in our consolidated financial statements at fair market value, which we adjust each period for changes in the fair market value, and refer to as marking to market, or mark-to-market. The fair market value of these derivative financial instruments reflects the estimated amounts that we would pay to transfer a liability or receive to sell an asset in an orderly transaction with market participants to terminate or close the contracts at the reporting date, taking into account the current unrealized losses or gains on open contracts. We apply the market approach to value substantially all of our derivative instruments. Actively traded external market quotes, data from pricing services and published indices are used to value our derivative instruments, which are fair-valued on a recurring basis. We may also use these inputs with internally developed methodologies that result in our best estimate of fair value.

Non-Qualified Hedges

Many of our derivative financial instruments qualify for hedge accounting treatment as set forth in the authoritative accounting guidance. However, we have transaction types associated with our commodity and interest rate derivative financial instruments where the hedge structure does not meet the requirements to apply hedge accounting. As a result, these derivative financial instruments do not qualify for hedge accounting and are referred to as non-qualifying. These non-qualifying derivative financial instruments are marked-to-market each period with the change in fair value, representing unrealized gains and losses, included in "Cost of natural gas," "Operating revenue," "Power" or "Interest expense" in our consolidated statements of income. These mark-to-market adjustments produce a degree of earnings volatility that can often be significant from period to period, but have no cash flow impact relative to changes in market prices. The cash flow impact occurs when the underlying physical transaction takes place in the future and the associated financial instrument contract settlement is made.

The following transaction types do not qualify for hedge accounting and contribute to the volatility of our income and cash flows:

Commodity Price Exposures:

- **Transportation**—In our Marketing segment, when we transport natural gas from one location to another, the pricing index used for natural gas sales is usually different from the pricing index used for natural gas purchases, which exposes us to market price risk relative to changes in those two indices. By entering into a basis swap, where we exchange one pricing index for another, we can effectively lock in the margin, representing the difference between the sales price and the purchase price, on the combined natural gas purchase and natural gas sale, removing any market price risk on the physical transactions. Although this represents a sound economic hedging strategy, the derivative financial instruments (i.e., the basis swaps) we use to manage the commodity price risk associated with these transportation contracts do not qualify for hedge accounting, since only the future margin has been fixed and not the future cash flow. As a result, the changes in fair value of these derivative financial instruments are recorded in earnings.
- **Storage**—In our Marketing segment, we use derivative financial instruments (i.e., natural gas swaps) to hedge the relative difference between the injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The intent of these derivative financial instruments is to lock in the margin, representing the difference between the price paid for the natural gas injected and the price received upon withdrawal of the natural gas from storage in a future period. We do not pursue cash flow hedge accounting treatment for these storage transactions since the underlying forecasted injection or withdrawal of natural gas may not occur in the period as originally forecast. This can occur because we have the flexibility to make changes in the underlying injection or withdrawal schedule, based on changes in market conditions. In addition, since the physical natural gas is recorded at the lower of cost or market, timing differences can result when the derivative financial instrument is settled in a period that is different from the period the physical natural gas is sold from storage. As a result, derivative financial instruments associated with our natural gas storage activities can create volatility in our earnings.

- **Natural Gas Collars**—In our Natural Gas segment, we previously entered into natural gas collars to hedge the sales price of natural gas. The natural gas collars were based on a New York Mercantile Exchange, or NYMEX, pricing index, while the physical gas sales were based on a different index. To better align the index of the natural gas collars with the index of the underlying sales, we de-designated the original cash flow hedging relationship with the intent of contemporaneously re-designating the natural gas collars as hedges of forecasted physical natural gas sales with a NYMEX pricing index. However, because the fair value of these derivative instruments was a liability to us at re-designation, they are considered net written options and, pursuant to the authoritative accounting guidance, do not qualify for hedge accounting. These derivatives are being marked-to-market, with the changes in fair value from the date of de-designation recorded to earnings each period. As a result, our operating income is subject to greater volatility due to movements in the prices of natural gas until the underlying long-term transactions are settled.
- **Optional Natural Gas Processing Volumes**—In our Natural Gas segment, we use derivative financial instruments to hedge the volumes of NGLs produced from our natural gas processing facilities. Some of our natural gas contracts allow us the choice of processing natural gas when it is economical and to cease doing so when processing becomes uneconomic. We have entered into derivative financial instruments to fix the sales price of a portion of the NGLs that we produce at our discretion and to fix the associated purchase price of natural gas required for processing. We typically designate derivative financial instruments associated with NGLs we produce per contractual processing requirements as cash flow hedges when the processing of natural gas is probable of occurrence. However, we are precluded from designating the derivative financial instruments as qualifying hedges of the respective commodity price risk when the discretionary processing volumes are subject to change. As a result, our operating income is subject to increased volatility due to fluctuations in NGL prices until the underlying transactions are settled or offset.
- **NGL Forward Contracts**—In our Natural Gas segment, we use forward contracts to fix the price of NGLs we purchase and store in inventory and to fix the price of NGLs that we sell from inventory to meet the demands of our customers that sell and purchase NGLs. Prior to April 1, 2009, these forward contracts were not treated as derivative financial instruments pursuant to the normal purchase normal sale, or NPNS, exception allowed under authoritative accounting guidance, since the forward contracts resulted in physical receipt or delivery of NGLs. However, evolving markets for NGLs have increased opportunities for a portion of our forward contracts to be settled net rather than physically receiving or delivering the NGLs. Accordingly, we have revoked the NPNS election on certain forward contracts associated with the liquids marketing operations of Dufour Petroleum, L.P., our wholly-owned subsidiary, executed after April 1, 2009. The forward contracts for which we have revoked the NPNS election do not qualify for hedge accounting and are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with fluctuations in NGL prices until the forward contracts are settled.
- **Natural Gas Forward Contracts**—In our Marketing segment, we use forward contracts to sell natural gas to our customers. Historically, we have not considered these contracts to be derivatives under the NPNS exception allowed by authoritative accounting guidance. In the first quarter of 2010, we determined that a sub-group of physical natural gas sales contracts with terms allowing for economic net settlement did not qualify for the NPNS scope exception, and are being marked-to-market each period with the changes in fair value recorded in earnings. As a result, our operating income is subject to additional volatility associated with the changes in fair value of these contracts.
- **Crude Oil Contracts**—In our Liquids segment, we use forward contracts to hedge a portion of the crude oil length inherent in the operation of our pipelines, which we subsequently sell at market rates. These hedges create a fixed sales price for the crude oil that we will receive in the future. We elected not to designate these derivative financial instruments as cash flow hedges, and as a result, will experience some additional volatility associated with fluctuations in crude oil prices until the underlying transactions are settled or offset.

- **Power Purchase Agreements**—In our Liquids segment, we use forward physical power agreements to fix the price of a portion of the power consumed by our pumping stations in the transportation of crude oil in our owned pipelines. We designate these derivative agreements as non-qualifying hedges because they fail to meet the criteria for cash flow hedging or the NPNS exception. As various states in which our pipelines operate have legislated either partially or fully deregulated power markets, we have the opportunity to create economic hedges on power exposure. As a result, our operating income is subject to additional volatility associated with changes in the fair value of these agreements due to fluctuations in forward power prices.

Except for physical power, in all instances related to the commodity exposures described above, the underlying physical purchase, storage and sale of the commodity is accounted for on a historical cost or market basis rather than on the mark-to-market basis we employ for the derivative financial instruments used to mitigate the commodity price risk associated with our storage and transportation assets. This difference in accounting (i.e., the derivative financial instruments are recorded at fair market value while the physical transactions are recorded at historical cost) can and has resulted in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated. Relating to the power purchase agreements, commodity power purchases are immediately consumed as part of pipeline operations and are subsequently recorded as actual power expenses each period.

We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as follows:

- Natural Gas and Marketing segments commodity-based derivatives—"Cost of natural gas"
- Liquids segment commodity-based derivatives—"Operating revenue" and "Power"
- Corporate interest rate derivatives—"Interest expense"

The changes in fair value of our derivatives are also presented as a reconciling item on our consolidated statements of cash flows. The following table presents the net unrealized gains and losses associated with the changes in fair value of our derivative financial instruments:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Liquids segment				
Non-qualified hedges	$33.7	$ (0.3)	$38.5	$ 0.1
Natural Gas segment				
Hedge ineffectiveness	(1.5)	3.1	(0.1)	4.5
Non-qualified hedges	17.0	(18.9)	16.1	10.0
Marketing				
Non-qualified hedges	1.6	1.3	(0.1)	(3.0)
Commodity derivative fair value net gains (losses)	50.8	(14.8)	54.4	11.6
Corporate				
Non-qualified interest rate hedges	(0.2)	(0.4)	(0.5)	(0.9)
Derivative fair value net gains (losses)	$50.6	$(15.2)	$53.9	$10.7

Derivative Positions

Our derivative financial instruments are included at their fair values in the consolidated statements of financial position as follows:

	September 30, 2011	December 31, 2010
	(in millions)	
Other current assets	$ 26.4	$ 37.1
Other assets, net	44.5	5.0
Accounts payable and other	(44.1)	(79.2)
Other long-term liabilities	(188.4)	(67.1)
	$(161.6)	$(104.2)

The changes in the net assets and liabilities associated with our derivatives are primarily attributable to the effects of new derivative transactions we have entered at prevailing market prices, settlement of maturing derivatives and the change in forward market prices of our remaining hedges. Our portfolio of derivative financial instruments is largely comprised of long-term natural gas, NGL and crude oil sales and purchase contracts.

We record the change in fair value of our highly effective cash flow hedges in "Accumulated other comprehensive income," or AOCI, until the derivative financial instruments are settled, at which time they are reclassified to earnings. Also included in AOCI are unrecognized losses of approximately $48.0 million associated with derivative financial instruments that qualified for and were classified as cash flow hedges of forecasted transactions that were subsequently de-designated. These losses are reclassified to earnings over the periods during which the originally hedged forecasted transactions affect earnings. During the three and nine month periods ended September 30, 2011, unrealized commodity hedge losses of $0.5 million and $5.6 million, respectively, were de-designated as a result of the hedges no longer meeting hedge accounting criteria. We estimate that approximately $37.8 million, representing unrealized net losses from our cash flow hedging activities based on pricing and positions at September 30, 2011, will be reclassified from AOCI to earnings during the next 12 months.

In connection with our issuance of the 2021 Notes, we paid $18.8 million to settle treasury locks we entered to hedge the interest payments on a portion of these obligations through the maturity date of the 2021 Notes. The settlement amount is being amortized from AOCI to "Interest expense" over the respective 10-year term of the 2021 Notes.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	September 30, 2011	December 31, 2010
	(in millions)	
Counterparty Credit Quality*		
AAA	$ (0.1)	$ —
AA	(114.8)	(48.7)
A	(55.7)	(61.3)
Lower than A	9.0	5.8
	$(161.6)	$(104.2)

* As determined by nationally-recognized statistical ratings organizations.

As the net value of our derivative financial instruments has decreased in response to changes in forward commodity prices, our outstanding financial exposure to third parties has also declined. When credit thresholds are met pursuant to the terms of our International Securities Dealers Association, or ISDA®, financial contracts, we have the right to require collateral from our counterparties. We have included any cash collateral received in the balances listed above. When we are in a position of posting collateral to cover our counterparties' exposure to our non-performance, the collateral is provided through letters of credit, which are not reflected above.

The ISDA® agreements and associated credit support, which govern our financial derivative transactions, contain no credit rating downgrade triggers that would accelerate the maturity dates of our outstanding transactions. A change in ratings is not an event of default under these instruments, and the maintenance of a specific minimum credit rating is not a condition to transacting under the ISDA® agreements. In the event of a credit downgrade, additional collateral may be required to be posted under the agreement if we are in a liability position to our counterparty, but the agreement will not automatically terminate and require immediate settlement of all future amounts due.

The ISDA® agreements, in combination with our master netting agreements, and credit arrangements governing our interest rate and commodity swaps require that collateral be posted per tiered contractual thresholds based on the credit rating of each counterparty. We generally provide letters of credit to satisfy such collateral requirements under our ISDA® agreements. These agreements will require additional collateral postings of up to 100% on net liability positions in the event of a credit downgrade below investment grade. Automatic termination clauses which exist are related only to non-performance activities, such as the refusal to post collateral when contractually required to do so. When we are holding an asset position, our counterparties are likewise required to post collateral on their liability (our asset) exposures, also determined by tiered contractual collateral thresholds. Counterparty collateral may consist of cash or letters of credit, both of which must be fulfilled with immediately available funds.

In the event that our credit ratings were to decline to the lowest level of investment grade, as determined by Standard & Poor's and Moody's, we would be required to provide additional amounts under our existing letters of credit to meet the requirements of our ISDA® agreements. For example, if our credit ratings had been at the lowest level of investment grade at September 30, 2011 we would have been required to provide additional letters of credit in the amount of $59.4 million.

At September 30, 2011 and December 31, 2010, we had credit concentrations in the following industry sectors, as presented below:

	September 30, 2011	December 31, 2010
	(in millions)	
United States financial institutions and investment banking entities	$ (97.3)	$ (53.2)
Non-United States financial institutions	(76.1)	(46.8)
Other	11.8	(4.2)
	$(161.6)	$(104.2)

We are holding no cash collateral on our asset exposures, and we have provided letters of credit totaling $123.9 million and $7.3 million relating to our liability exposures pursuant to the margin thresholds in effect at September 30, 2011 and December 31, 2010, respectively, under our ISDA® agreements.

Gross derivative balances are presented below before the effects of collateral received or posted and without the effects of master netting arrangements. Both our assets and liabilities are adjusted for non-performance risk, which is statistically derived. This credit valuation adjustment model considers existing derivative asset and liability balances in conjunction with contractual netting and collateral arrangements, current market data such as credit default swap rates and bond spreads and probability of default assumptions to quantify an adjustment to fair value. For credit modeling purposes, collateral received is included in the calculation of our assets, while any collateral posted is excluded from the calculation of the credit adjustment. Our credit exposure for these over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contracts. A reconciliation between the derivative balances presented at gross values rather than the net amounts we present in our other derivative disclosures, is also provided below.

Effect of Derivative Instruments on the Consolidated Statements of Financial Position

	Asset Derivatives			Liability Derivatives		
		Fair Value at			Fair Value at	
	Financial Position Location	September 30, 2011	December 31, 2010	Financial Position Location	September 30, 2011	December 31, 2010
			(in millions)			
Derivatives designated as hedging instruments[1]						
Interest rate contracts . . .	Other current assets	$ —	$22.9	Accounts payable and other	$ (21.4)	$ (21.4)
Interest rate contracts . . .	Other assets, net	—	2.5	Other long-term liabilities	(187.3)	(44.0)
Commodity contracts . . .	Other current assets	10.3	10.7	Accounts payable and other	(18.8)	(43.4)
Commodity contracts . . .	Other assets, net	23.1	14.1	Other long-term liabilities	(11.4)	(38.1)
		33.4	50.2		(238.9)	(146.9)
Derivatives not designated as hedging instruments						
Interest rate contracts . . .	Other current assets	3.7	5.1	Accounts payable and other	(3.3)	(4.6)
Interest rate contracts . . .	Other assets, net	5.2	6.6	Other long-term liabilities	(4.8)	(5.9)
Commodity contracts . . .	Other current assets	49.4	23.7	Accounts payable and other	(37.5)	(35.1)
Commodity contracts . . .	Other assets, net	33.3	8.7	Other long-term liabilities	(2.1)	(6.0)
		91.6	44.1		(47.7)	(51.6)
Total derivative instruments		$125.0	$94.3		$(286.6)	$(198.5)

(1) Includes items currently designated as hedging instruments. Excludes the portion of de-designated hedges which may have a component remaining in AOCI.

Effect of Derivative Instruments on the Consolidated Statements of Income and Accumulated Other Comprehensive Income

Derivatives in Cash Flow Hedging Relationships	Amount of gain (loss) recognized in AOCI on Derivative (Effective Portion)	Location of gain (loss) reclassified from AOCI to earnings (Effective Portion)	Amount of gain (loss) reclassified from AOCI to earnings (Effective Portion)	Location of gain (loss) recognized in earnings on derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]	Amount of gain (loss) recognized in earnings on derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)[1]
		(in millions)			
For the three month period ended September 30, 2011					
Interest rate contracts .	$(141.8)	Interest expense	$ (7.0)	Interest expense	$(0.1)
Commodity contracts .	89.2	Cost of natural gas . . .	(15.4)	Cost of natural gas . . .	(1.4)
Total	$ (52.6)		$(22.4)		$(1.5)
For the three month period ended September 30, 2010					
Interest rate contracts .	$ (50.4)	Interest expense	$ (1.9)	Interest expense	$ 0.2
Commodity contracts .	(13.9)	Cost of natural gas . . .	(1.7)	Cost of natural gas . . .	3.1
Total	$ (64.3)		$ (3.6)		$ 3.3
For the nine month period ended September 30, 2011					
Interest rate contracts .	$(168.7)	Interest expense	$(20.4)	Interest expense	$(0.1)
Commodity contracts .	59.9	Cost of natural gas . . .	(48.1)	Cost of natural gas . . .	(0.1)
Total	$(108.8)		$(68.5)		$(0.2)
For the nine month period ended September 30, 2010					
Interest rate contracts .	$(150.5)	Interest expense	$ (5.3)	Interest expense	$ 0.2
Commodity contracts .	53.3	Cost of natural gas . . .	(17.2)	Cost of natural gas . . .	4.5
Total	$ (97.2)		$(22.5)		$ 4.7

(1) Includes only the ineffective portion of derivatives that are designated as hedging instruments and does not include net gains or losses associated with derivatives that do not qualify for hedge accounting treatment.

Effect of Derivative Instruments on Consolidated Statements of Income

Derivatives Not Designated as Hedging Instruments	Location of Gain or (Loss) Recognized in Earnings	For the three month period ended September 30, 2011	2010	For the nine month period ended September 30, 2011	2010
		Amount of Gain or (Loss) Recognized in Earnings[1]		Amount of Gain or (Loss) Recognized in Earnings[1]	
		(in millions)			
Interest rate contracts	Interest expense	$ (0.2)	$ (0.4)	$ (0.5)	$(0.9)
Commodity contracts	Operating revenue	33.3	(0.3)	38.5	0.1
Commodity contracts	Power	0.4	—	—	—
Commodity contracts	Cost of natural gas	18.6	(17.6)	16.0	7.0
Total		$52.1	$(18.3)	$54.0	$ 6.2

(1) Includes only net gains or losses associated with those derivatives that do not qualify for hedge accounting treatment and does not include the ineffective portion of derivatives that are designated as hedging instruments.

Gross to Net Presentation Reconciliation of Derivative Assets and Liabilities

	September 30, 2011 Assets	Liabilities	Total	December 31, 2010 Assets	Liabilities	Total
	(in millions)					
Fair value of derivatives—gross presentation	$125.0	$(286.6)	$(161.6)	$ 94.3	$(198.5)	$(104.2)
Effects of netting agreements	(54.1)	54.1	—	(52.2)	52.2	—
Fair value of derivatives—net presentation	$ 70.9	$(232.5)	$(161.6)	$ 42.1	$(146.3)	$(104.2)

Inputs to Fair Value Derivative Instruments

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2011 and December 31, 2010. We classify financial assets and liabilities in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect our valuation of the financial assets and liabilities and their placement within the fair value hierarchy.

	September 30, 2011 Level 1	Level 2	Level 3	Total	December 31, 2010 Level 1	Level 2	Level 3	Total
	(in millions)							
Interest rate contracts	$—	$(207.9)	$ —	$(207.9)	$—	$(38.8)	$ —	$ (38.8)
Commodity contracts:								
Financial	—	44.0	(14.3)	29.7	—	(52.4)	(24.8)	(77.2)
Physical	—	—	10.6	10.6	—	—	3.4	3.4
Commodity options	—	—	6.0	6.0	—	(0.2)	8.6	8.4
Total	$—	$(163.9)	$ 2.3	$(161.6)	$—	$(91.4)	$(12.8)	$(104.2)

The table below provides a reconciliation of changes in the fair value of our Level 3 financial assets and liabilities measured on a recurring basis from January 1, 2011 to September 30, 2011. No transfers of assets between any of the Levels occurred during the period.

	Commodity Financial Contracts	Commodity Physical Contracts	Commodity Options	Total
	(in millions)			
Beginning balance as of January 1, 2011	$(24.8)	$ 3.4	$ 8.6	$(12.8)
Transfer out of Level 3[1]	—	—	—	—
Gains or losses				
Included in earnings (or changes in net assets)	(20.0)	10.3	0.2	(9.5)
Included in other comprehensive income	(18.3)	—	(3.2)	(21.5)
Purchases, issuances, sales and settlements Purchases	—	—	1.1	1.1
Settlements[2]	48.8	(3.1)	(0.7)	45.0
Ending balance as September 30, 2011	$(14.3)	$10.6	$ 6.0	$ 2.3
Amount of changes in net assets attributable to the change in unrealized gains or losses related to assets still held at the reporting date	$ (6.6)	$ 9.2	$ 0.6	$ 3.2
Amounts reported in operating revenue	$ 4.9	$ —	$—	$ 4.9

(1) Our policy is to recognize transfers as of the last day of the reporting period.

(2) Settlements represent the realized portion of forward contracts.

Fair Value Measurements of Commodity Derivatives

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at September 30, 2011 and December 31, 2010.

	At September 30, 2011						At December 31, 2010	
			Wtd. Average Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	3,197,234	$ 3.76	$ 4.51	$ —	$ (2.4)	$ 0.4	$ (4.9)
	NGL	34,762	$87.47	$49.58	$ 1.3	$ —	$ 6.8	$ —
	Crude Oil	90,000	$79.29	$90.71	$ —	$ (1.0)	$ 0.4	$ —
Receive fixed/pay variable	Natural Gas	4,904,397	$ 4.13	$ 3.78	$ 2.1	$ (0.3)	$ 2.6	$ (6.7)
	NGL	1,330,088	$51.73	$63.94	$ 2.6	$(18.8)	$ 5.0	$(38.8)
	Crude Oil	467,568	$79.78	$78.81	$ 2.0	$ (1.6)	$—	$(22.9)
Receive variable/pay variable	Natural Gas	24,661,617	$ 3.72	$ 3.68	$ 1.4	$ (0.6)	$ 5.0	$ (1.2)
Physical Contracts								
Receive fixed/pay variable	NGL	2,028,798	$76.95	$74.14	$ 6.2	$ (0.5)	$ 0.5	$ (4.4)
	Crude Oil	219,067	$89.88	$79.38	$ 2.3	$ —	$—	$ (1.9)
Receive variable/pay fixed	NGL	1,665,026	$74.02	$76.08	$ 0.4	$ (3.8)	$ 1.6	$ —
	Crude Oil	159,700	$79.33	$87.66	$ —	$ (1.3)	$ 1.1	$ —
Pay fixed	Power(4)	18,489	$30.86	$44.36	$ —	$ (0.2)	$—	$ (0.8)
Receive variable/pay variable	Crude Oil	824,953	$80.13	$79.42	$ 2.3	$ (1.8)	$ 0.5	$ (0.2)
	NGL	2,492,120	$71.63	$70.67	$ 5.9	$ (3.5)	$ 6.2	$ (1.4)
	Natural Gas	11,143,979	$ 3.73	$ 3.69	$ 0.4	$ —	$ 1.1	$ —
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	2,362,813	$ 4.13	$ 6.40	$ —	$ (5.3)	$—	$ (3.8)
	NGL	91,500	$16.65	$16.80	$ —	$ —	$—	$ —
Receive fixed/pay variable	Natural Gas	4,864,120	$ 4.78	$ 4.13	$ 3.8	$ (0.7)	$ 1.7	$ (2.1)
	NGL	2,551,428	$54.00	$55.68	$ 9.0	$(13.3)	$ 8.0	$ (7.6)
	Crude Oil	1,455,216	$88.79	$79.30	$15.8	$ (2.0)	$—	$(10.7)
Receive variable/pay variable	Natural Gas	54,914,000	$ 4.17	$ 4.15	$ 2.1	$ (0.8)	$ 1.0	$ (0.8)
Physical Contracts								
Receive variable/pay fixed	NGL	25,000	$76.91	$72.39	$ 0.1	$ —	$—	$ —
Receive fixed/pay variable	NGL	230,791	$79.25	$77.09	$ 0.7	$ (0.2)	$—	$ —
Receive variable/pay variable	Natural Gas	20,780,946	$ 4.18	$ 4.13	$ 1.0	$ —	$ 0.6	$ —
	NGL	2,531,486	$63.69	$62.74	$ 6.4	$ (4.0)	$ 0.7	$ —
Pay fixed	Power(4)	62,330	$35.74	$40.29	$ —	$ (0.3)	$—	$ —
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	93,066	$ 4.72	$ 5.19	$ —	$ —	$—	$ —
Receive fixed/pay variable	Natural Gas	1,009,600	$ 8.41	$ 4.69	$ 3.7	$ —	$ 3.3	$ —
	NGL	994,260	$64.86	$68.09	$ 1.3	$ (4.5)	$ 0.3	$ (3.2)
	Crude Oil	1,430,435	$93.38	$83.42	$16.2	$ (2.1)	$ 2.2	$ (7.4)
Receive variable/pay variable	Natural Gas	31,070,000	$ 4.76	$ 4.74	$ 0.6	$ (0.1)	$ 0.1	$ (0.2)
Physical Contracts								
Receive variable/pay variable	Natural Gas	7,845,782	$ 4.79	$ 4.73	$ 0.4	$ —	$ 0.2	$ —
	NGL	321,429	$52.68	$51.59	$ 0.3	$ —	$—	$ —
Pay fixed	Power(4)	42,924	$40.15	$42.86	$ —	$ (0.1)	$—	$ —
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 5.13	$ 5.22	$ —	$ —	$—	$ —
Receive fixed/pay variable	NGL	381,425	$77.58	$74.59	$ 1.8	$ (0.7)	$—	$ (1.1)
	Crude Oil	1,228,955	$94.27	$84.71	$11.6	$ (0.1)	$—	$ (2.8)
Receive variable/pay variable	Natural Gas	6,300,000	$ 5.18	$ 5.17	$ 0.1	$ —	$—	$ (0.1)
Physical Contracts								
Receive variable/pay variable	Natural Gas	1,115,075	$ 5.29	$ 5.17	$ 0.1	$ —	$—	$ —
Pay fixed	Power(4)	58,608	$43.47	$46.58	$ —	$ (0.2)	$—	$ —
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	Crude Oil	865,415	$97.72	$85.74	$10.0	$ —	$—	$ (0.7)
	NGL	109,500	$88.36	$76.26	$ 1.3	$ —	$—	$ (0.1)
Physical Contracts								
Receive variable/pay variable	Natural Gas	1,115,075	$ 5.52	$ 5.39	$ 0.1	$ —	$—	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$99.31	$86.78	$ 0.5	$ —	$—	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	745,420	$ 5.74	$ 5.61	$ 0.1	$ —	$—	$ —

(1) Volumes of natural gas are measured in millions of British Thermal Units, or MMBtu, whereas volumes of NGL and crude oil are measured in barrels, or Bbl. Our power purchase agreements are measured in Megawatt hours, or MWh.
(2) Weighted average prices received and paid are in $/MMBtu for natural gas, $/Bbl for NGL and crude oil and $/MWh for power.
(3) The fair value is determined based on quoted market prices at September 30, 2011 and December 31, 2010, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $3.4 million of losses and $0.6 million of gains at September 30, 2011 and December 31, 2010, respectively.
(4) For physical power, the receive price shown represents the index price used for valuation purposes.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at September 30, 2011 and December 31, 2010.

	At September 30, 2011						At December 31, 2010	
					Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Strike Price[2]	Market Price[2]	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2011								
Calls (written)	Natural Gas[4]	92,000	$ 4.31	$ 3.81	$—	$—	$—	$(0.2)
Puts (purchased)	Natural Gas[4]	92,000	$ 3.40	$ 3.81	$—	$—	$—	$—
	NGL	159,896	$54.79	$65.59	$ 0.4	$—	$ 3.6	$—
	Crude Oil	54,740	$88.65	$79.37	$ 0.7	$—	$ 1.3	$—
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	613,782	$44.85	$45.31	$ 5.1	$—	$ 3.9	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.
(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.
(3) The fair value is determined based on quoted market prices at September 30, 2011 and December 31, 2010, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of losses at September 30, 2011 and $0.1 million of losses at December 31, 2010.
(4) Indicates transactions which, in combination, create a collar, representing a floor and ceiling on the price and provide long-term price protection.

Fair Value Measurements of Interest Rate Derivatives

We enter into interest rate swaps, caps and derivative financial instruments with similar characteristics to manage the cash flow associated with future interest rate movements on our indebtedness. The following table provides information about our current interest rate derivatives for the specified periods.

				Fair Value[2]	
Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	September 30, 2011	December 31, 2010
	(dollars in millions)				
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$600	4.15%	$ (48.0)	$(51.8)
Interest Rate Swaps—Pay Fixed	Non-qualifying	$125	4.35%	$ (8.3)	$(10.7)
Interest Rate Swaps—Pay Float	Non-qualifying	$125	4.75%	$ 9.1	$ 11.9
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$300	2.43%	$ (4.0)	$ 1.9
Contracts settling prior to maturity					
2011—Pre-issuance Hedges[3]	Cash Flow Hedge	$300	2.92%	$ —	$ 23.4
2012—Pre-issuance Hedges	Cash Flow Hedge	$600	4.56%	$(114.0)	$(13.7)
2013—Pre-issuance Hedges	Cash Flow Hedge	$300	4.62%	$ (49.6)	$ (0.3)
2014—Pre-issuance Hedges	Cash Flow Hedge	$750	3.15%	$ (12.1)	$ —

(1) Interest rate derivative contracts are based on the one-month or three-month London Inter-Bank Offered Rate, or LIBOR.
(2) The fair value is determined from quoted market prices at September 30, 2011 and December 31, 2010, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $18.9 million of gains at September 30, 2011 and $0.5 million of gains at December 31, 2010.
(3) Settled in connection with the issuance of our 2021 Notes.

11. INCOME TAXES

We are not a taxable entity for United States federal income tax purposes, or for the majority of states that impose an income tax. Taxes on our net income generally are borne by our unit holders through the allocation of taxable income. Our income tax expense results from the enactment of state income tax laws that apply to entities organized as partnerships by the States of Texas and Michigan. We computed our income tax expense by applying a Texas state income tax rate to modified gross margin and a Michigan state income tax rate to modified gross receipts. The Texas state income tax rate was 0.5% for the nine month periods ended September 30, 2011 and 2010. The Michigan state income tax rate was 0.2% for the nine month periods ended September 30, 2011 and 2010.

On May 25, 2011, the Governor of Michigan signed legislation implementing a new corporate income tax system. The new tax system becomes effective January 1, 2012 and repeals the Michigan Business Tax, or MBT, which imposes tax on individuals, LLCs, trusts, partnerships, S corporations, and C corporations and replaces it with the Michigan Corporate Income Tax, or CIT. The CIT only taxes entities classified as C Corporations, therefore, the Partnership is excluded from the CIT and will no longer pay Michigan income taxes beginning in 2012. Due to this change as of June 30, 2011 we reversed deferred tax liabilities of $1.2 million that were previously recognized on our consolidated statements of financial position, which decreased “Income tax expense” in our consolidated statements of income for the three and nine month periods ended September 30, 2011, to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting related to Michigan income taxes.

Our income tax expense is $2.1 million and $2.9 million and $5.3 million and $7.5 million for the three and nine month periods ended September 30, 2011 and 2010 respectively.

At September 30, 2011 and December 31, 2010 we have included a current income tax payable of $6.7 million and $7.9 million in “Property and other taxes payable,” respectively. In addition, at September 30, 2011 and December 31, 2010, we have included a deferred income tax liability of $3.2 million and $3.6 million, respectively, in “Other long-term liabilities,” on our consolidated statements of financial position to reflect the tax associated with the difference between the net basis in assets and liabilities for financial and state tax reporting.

12. OIL MEASUREMENT ADJUSTMENTS

Oil measurement adjustments occur as part of the normal operations associated with our liquid petroleum operations. The three types of oil measurement adjustments that routinely occur on our systems include:

- Physical, which result from evaporation, shrinkage, differences in measurement (including sediment and water measurement) between receipt and delivery locations and other operational conditions;
- Degradation resulting from mixing at the interface within our pipeline systems or terminal and storage facilities between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- Revaluation, which are a function of crude oil prices, the level of our carriers inventory and the inventory positions of customers.

Quantifying oil measurement adjustments are difficult because: (1) physical measurements of volumes are not practical, as products continuously move through our pipelines, which are primarily located underground; (2) the extensive length of our pipeline systems and (3) the numerous grades and types of crude oil products we carry. We utilize engineering-based models and operational assumptions to estimate product volumes in our systems and associated oil measurement adjustments. Material changes in our assumptions may result in revisions to our oil measurement estimates in the period determined.

In June 2011, we recognized $52.2 million from the settlement of a dispute with a shipper on our Lakehead crude oil pipeline system. We received the cash for that settlement in July 2011. The dispute related to oil measurement adjustments we had previously recognized in prior years and was therefore recorded to "Oil measurement adjustments," as a reduction to operating expenses, for the nine month period ended September 30, 2011 in our consolidated statements of income.

13. SEGMENT INFORMATION

Our business is divided into operating segments, defined as components of the enterprise, about which financial information is available and evaluated regularly by our Chief Operating Decision Maker in deciding how resources are allocated and performance is assessed.

Each of our reportable segments is a business unit that offers different services and products that is managed separately, since each business segment requires different operating strategies. We have segregated our business activities into three distinct operating segments:

- Liquids;
- Natural Gas; and
- Marketing.

The following tables present certain financial information relating to our business segments and corporate activities:

	For the three month period ended September 30, 2011				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$363.3	$1,832.1	$584.2	$ —	$2,779.6
Less: Intersegment revenue	0.3	395.7	11.4	—	407.4
Operating revenue	363.0	1,436.4	572.8	—	2,372.2
Cost of natural gas	—	1,233.3	572.1	—	1,805.4
Environmental costs, net of recoveries	56.1	—	—	—	56.1
Oil measurement adjustments	(2.8)	—	—	—	(2.8)
Operating and administrative	74.4	104.5	1.9	0.5	181.3
Power	37.7	—	—	—	37.7
Depreciation and amortization	49.2	29.7	—	—	78.9
Operating income (loss)	148.4	68.9	(1.2)	(0.5)	215.6
Interest expense	—	—	—	78.7	78.7
Income (loss) from continuing operations before income tax expense	148.4	68.9	(1.2)	(79.2)	136.9
Income tax expense	—	—	—	2.1	2.1
Net income (loss)	148.4	68.9	(1.2)	(81.3)	134.8
Less: Net income attributable to the noncontrolling interest	—	—	—	12.2	12.2
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$148.4	$ 68.9	$ (1.2)	$(93.5)	$ 122.6

(1) Corporate consists of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

	For the three month period ended September 30, 2010				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 301.4	$1,385.6	$599.7	$ —	$2,286.7
Less: Intersegment revenue	0.3	388.7	8.4	—	397.4
Operating revenue	301.1	996.9	591.3	—	1,889.3
Cost of natural gas	—	869.1	586.5	—	1,455.6
Environmental costs, net of recoveries	477.6	—	—	—	477.6
Oil measurement adjustments	(0.2)	—	—	—	(0.2)
Operating and administrative	59.6	78.3	2.3	2.1	142.3
Power	36.7	—	—	—	36.7
Depreciation and amortization	48.0	31.6	0.1	—	79.7
Impairment charge	10.3	—	—	—	10.3
Operating income (loss)	(330.9)	17.9	2.4	(2.1)	(312.7)
Interest expense	—	—	—	70.1	70.1
Other expense	—	—	—	0.6	0.6
Income (loss) from continuing operations before income tax expense	(330.9)	17.9	2.4	(72.8)	(383.4)
Income tax expense	—	—	—	2.9	2.9
Net income (loss)	(330.9)	17.9	2.4	(75.7)	(386.3)
Less: Net income attributable to the noncontrolling interest	—	—	—	20.1	20.1
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$(330.9)	$ 17.9	$ 2.4	$(95.8)	$ (406.4)

(1) Corporate consists of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

	As of and for the nine month period ended September 30, 2011				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 975.7	$5,528.0	$1,704.5	$ —	$ 8,208.2
Less: Intersegment revenue	1.0	1,143.8	30.3	—	1,175.1
Operating revenue	974.7	4,384.2	1,674.2	—	7,033.1
Cost of natural gas	—	3,826.8	1,669.4	—	5,496.2
Environmental costs, net of recoveries	45.2	(0.4)	—	—	44.8
Oil measurement adjustments	(61.5)	—	—	—	(61.5)
Operating and administrative	218.5	289.8	5.2	2.5	516.0
Power	107.2	—	—	—	107.2
Depreciation and amortization	146.5	110.4	—	—	256.9
Operating income (loss)	518.8	157.6	(0.4)	(2.5)	673.5
Interest expense	—	—	—	236.6	236.6
Other income	—	—	—	6.0	6.0
Income (loss) from continuing operations before income tax expense	518.8	157.6	(0.4)	(233.1)	442.9
Income tax expense	—	—	—	5.3	5.3
Net income (loss)	518.8	157.6	(0.4)	(238.4)	437.6
Less: Net income attributable to the noncontrolling interest	—	—	—	41.0	41.0
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 518.8	$ 157.6	$ (0.4)	$(279.4)	$ 396.6
Total assets	$6,050.6	$4,682.4	$ 209.7	$ 379.9	$11,322.6
Capital expenditures (excluding acquisitions)	$ 444.9	$ 302.7	$ —	$ 8.2	$ 755.8

(1) Corporate consists of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

	As of and for the nine month period ended September 30, 2010				
	Liquids	Natural Gas	Marketing	Corporate[1]	Total
			(in millions)		
Total revenue	$ 883.6	$4,022.8	$1,842.5	$ —	$ 6,748.9
Less: Intersegment revenue	0.9	1,152.6	27.5	—	1,181.0
Operating revenue	882.7	2,870.2	1,815.0	—	5,567.9
Cost of natural gas	—	2,447.7	1,802.5	—	4,250.2
Environmental costs, net of recoveries	482.1	—	—	—	482.1
Oil measurement adjustments	(0.2)	—	—	—	(0.2)
Operating and administrative	184.0	215.8	7.0	3.3	410.1
Power	105.5	—	—	—	105.5
Depreciation and amortization	131.7	93.3	0.2	—	225.2
Impairment charge	10.3	—	—	—	10.3
Operating income (loss)	(30.7)	113.4	5.3	(3.3)	84.7
Interest expense	—	—	—	199.0	199.0
Other income	—	—	—	16.1	16.1
Income (loss) from continuing operations before income tax expense	(30.7)	113.4	5.3	(186.2)	(98.2)
Income tax expense	—	—	—	7.5	7.5
Net income (loss)	(30.7)	113.4	5.3	(193.7)	(105.7)
Less: Net income attributable to the noncontrolling interest	—	—	—	45.3	45.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ (30.7)	$ 113.4	$ 5.3	$(239.0)	$ (151.0)
Total assets	$5,399.9	$4,308.3	$ 205.0	$ 249.0	$10,162.2
Capital expenditures (excluding acquisitions)	$ 317.2	$ 206.2	$ —	$ 5.7	$ 529.1

(1) Corporate consists of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

14. REGULATORY MATTERS

Regulatory Accounting

We apply the authoritative accounting provisions applicable to the regulated operations of our Southern Access and Alberta Clipper pipelines. The rates for both the Southern Access and Alberta Clipper pipelines are based on a cost-of-service recovery model that follows the FERC's authoritative guidance and is subject to annual filing requirements with the FERC. Under our cost-of-service tolling methodology, we calculate tolls based on forecast volumes and costs. A difference between forecast and actual results causes an under or over collection of revenue in any given year. Under the authoritative accounting provisions applicable to our regulated operations, over or under collections of revenue are recognized in the financial statements currently and these amounts are realized or settled as cash the following year. This accounting model matches earnings to the period with which they relate and conforms to how we recover our costs associated with these expansions through the annual cost-of-service filings with our customers and the FERC. The assets and liabilities that we recognize for regulatory purposes are recorded in "Other current assets" and "Accounts payable and other," respectively, on our consolidated statements of financial position.

Southern Access Pipeline

For 2011, we over collected revenue for our Southern Access Pipeline because the actual volumes were higher than the forecast volumes used to calculate the toll surcharge. As a result, for the three and nine month periods ended September 30, 2011, we reduced our revenues by $1.4 million and $15.2 million, respectively, on our consolidated statements of income with a corresponding regulatory liability on our consolidated statements of financial position at September 30, 2011 for the differences in transportation volumes. The amounts will be refunded through our tolls beginning April 2012 when we update our transportation rates to account for the higher than estimated delivered volumes.

For 2010, we over collected revenue for our Southern Access Pipeline because the actual volumes were higher than the forecast volumes used to calculate the toll surcharge. In addition, the actual costs recognized in 2010 were lower than the forecasted costs used to calculate the toll charge. As a result, in 2010 we reduced our revenues for the amounts we over collected and recorded a regulatory liability. We began to amortize this regulatory liability on a straight-line basis during 2011 to recognize the amounts we previously collected as revenue due to the lower toll rate in 2011 and to account for the over collected amounts. For the three and nine month periods ended September 30, 2011, we increased our revenues by $0.8 million and $2.9 million, respectively, on our consolidated statement of income with a corresponding amount reducing the regulatory liability on our consolidated statement of financial position at September 30, 2011. At September 30, 2011 and December 31, 2010, we had a $0.7 million and $3.6 million in regulatory liabilities, respectively, on our consolidated statements of financial position. The amounts are being refunded to our customers through our tolls, which began in April 2011 when our transportation rates, which account for the higher delivered volumes and lower costs than estimated, became effective.

For 2009, we under collected revenue for our Southern Access Pipeline in part because actual volumes were lower than the forecast volumes used to calculate the toll surcharge, resulting in a regulatory receivable, the balance of which was $2.1 million, on our consolidated statement of financial position as of December 31, 2010. We collected the $2.1 million regulatory receivable in the first quarter of 2011.

Alberta Clipper Pipeline

Under the authoritative accounting provisions applicable to regulated operations, we are permitted to capitalize and recover costs for rate-making purposes that include an allowance for equity costs during construction, referred to as AEDC. In connection with the construction of the Alberta Clipper Pipeline, we have recorded AEDC in "Property, plant and equipment, net" on our consolidated statements of financial position in amounts totaling $27.9 million at both September 30, 2011 and December 31, 2010. Related to the recognition of AEDC, we also recorded $14.3 million of "Other income" in our consolidated statement of income for the nine month period ended September 30, 2010. For the three month period ended September 30, 2010, we did not record any additional income related to AEDC.

For 2011, we have over collected revenue on our Alberta Clipper Pipeline because the actual volumes were higher than the forecast volumes used to calculate the toll surcharge. Offsetting the impact from the difference in volumes were actual costs recognized in 2011 that were higher than the forecasted costs used to calculate the toll charge. As a result, for the three and nine month periods ended September 30, 2011, we reduced our revenues by $8.4 million and $23.6 million, respectively, on our consolidated statement of income with a corresponding increase in the regulatory liability on our consolidated statement of financial position at September 30, 2011 for the differences in transportation volumes and costs. We will begin to reimburse these amounts to our customers in April 2012 when we update our transportation rates to account for the higher delivered volumes and higher costs than estimated.

During 2010, we over collected revenue on our Alberta Clipper Pipeline because the actual operating costs recognized in 2010 were lower than the forecasted costs used to calculate the toll charge. As of September 30, 2011 and December 31, 2010, we had regulatory liabilities of $2.5 million and $10.1 million, respectively, in our consolidated statements of financial position for the difference in costs. The amounts are being refunded to our customers through transportation rates, which became effective in April 2011 and account for the lower costs than estimated.

Regulatory Liability for Southern Lights Pipeline In-Service Delay

In December 2006, as part of the regulatory approval process for its pipeline, Enbridge Pipelines (Southern Lights) L.L.C., or Southern Lights, agreed to the request made by the Canadian Association of Petroleum Producers, referred to as CAPP, to delay the in-service date of its pipeline from January 1, 2010 to July 1, 2010. In exchange for Southern Light's postponement of the in-service date of its pipeline, CAPP agreed to reimburse Southern Lights for any carrying costs incurred during this period as a result of the delayed in-service date. The carrying costs were collected by us through the transportation rates charged on our Lakehead system beginning on April 1, 2010. As of September 30, 2011, we had $31.6 million recorded as a regulatory liability on our consolidated statement of financial position for amounts we over collected in connection with the Southern Lights in-service delay. We will reduce the transportation rates we charge the shippers in the future for the additional amounts we collected beginning in April 2012 when we update the transportation rates on our Lakehead system.

FERC Transportation Tariffs

Effective April 1, 2011, we filed our annual tariff rate adjustment with the FERC to reflect true-ups for the difference between estimated and actual cost and throughput data for the prior year and our projected costs and throughput for 2011 related to our expansion projects. Also included was a supplement to our FSM for recovery of the costs related to the 2010 and 2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order and as discussed in Note 9—*Commitments and Contingencies—Pipeline Integrity Commitment*. The FSM, which was approved in July 2004, is a component of our Lakehead system's overall rate structure and allows for the recovery of costs for enhancements or modifications to our Lakehead system.

This tariff filing decreased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois by approximately $0.21 per barrel, to an average of approximately $1.76 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

On May 2, 2011, we filed FERC Tariff 45.0.0 to establish International Joint Tariff rates applicable to the transportation of petroleum from all receipt points in Western Canada on Enbridge Pipelines Inc., or EPI's, Canadian Mainline system to all delivery points on the Lakehead pipeline system owned by the OLP and delivery points on the Canadian mainline located downstream of the Lakehead system. This tariff filing became effective July 1, 2011.

Effective July 1, 2011, we increased the rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In May 2011, the FERC determined that the annual change in the Producer Price Index for Finished Goods, or PPI-FG, plus 2.65 percent (PPI-FG + 2.65 percent) should be the oil pricing index for the five year period ending July 2016. The index is used to establish rate ceiling levels for oil pipeline rate changes. The increase in rates is due to a increase in the Producer Price Index for Finished Goods as compared with prior periods. For our Lakehead system, indexing applies only to the base rates and does not apply to the SEP II, Terrace and Facilities surcharges, which include the Southern Access Pipeline and Alberta Clipper Project.

15. SUBSEQUENT EVENTS

Distribution to Partners

On October 28, 2011, the board of directors of Enbridge Management declared a distribution payable to our partners on November 14, 2011. The distribution will be paid to unit holders of record as of November 4, 2011, of our available cash of $173.2 million at September 30, 2011, or $0.53250 per limited partner unit. Of this distribution, $153.1 million will be paid in cash, $19.7 million will be distributed in i-units to our i-unitholder and $0.4 million will be retained from our General Partner in respect of the i-unit distribution to maintain its two percent general partner interest.

Distribution to Series AC Interests

On October 28, 2011, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP will pay $15.3 million to the noncontrolling interest in the Series AC, while $7.7 million will be paid to us.

16. SUPPLEMENTAL CASH FLOWS INFORMATION

The following table provides supplemental information for the item labeled "Other" in the "Cash from operating activities" section of our consolidated statements of cash flows.

	For the nine month period ended September 30,	
	2011	2010
	(in millions)	
Discount accretion	$ 0.5	$ 0.3
Amortization of debt issuance and hedging costs	13.3	15.7
Deferred income taxes	(0.9)	1.9
Allowance for equity used during construction	—	(14.3)
Allowance for doubtful accounts	0.6	(4.0)
Gain on sale of CO2 plant	(1.5)	—
Other	0.8	2.6
	$12.8	$ 2.2

17. RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting Standards Update—Fair Value Measurement

In May 2011, the Financial Accounting Standards Board, or FASB, issued an amendment to the guidance on fair value measurement as part of the FASB's joint project with the International Accounting Standards Board, or IASB, to achieve common fair value measurement and disclosure requirements in United States generally accepted accounting principles, or GAAP, and International Financial Reporting Standards, or IFRS. The key changes relevant to our business include enhanced disclosures requiring additional information about unobservable inputs and valuation methods utilized and requiring the fair value hierarchy level of assets and liabilities not recorded at fair value but where fair value disclosure is required.

The accounting update is effective for the first reporting period beginning after December 15, 2011, with early application prohibited. The guidance will require prospective application. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

Accounting Standards Update—Presentation of Comprehensive Income

In June 2011, the FASB issued guidance on the presentation of comprehensive income as part of the FASB's joint project with the IASB, requiring presentation of net income and other comprehensive income either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of net income and other comprehensive income. The guidance eliminated the option to report other comprehensive income and its components in the statement of changes in equity and the disclosure of reclassification adjustments in the footnotes. The guidance does not change which components of comprehensive income are recognized in net income or other comprehensive income, when an item of other comprehensive income must be reclassified to net income or the earnings-per-share computation.

The accounting update is effective for the first reporting period beginning after December 15, 2011, with early application permitted. The guidance requires retrospective application. We do not intend to adopt the provisions of this pronouncement early. Our adoption of this pronouncement will require us to modify the items we present in the consolidated statements of comprehensive income

Accounting Standards Update—Testing Goodwill for Impairment

In September 2011, the FASB issued Accounting Standard No. 2011-08, *Testing Goodwill for Impairment,* which is intended to reduce the overall costs and the complexity of impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity no longer will be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The standard does not change the current two-step test and applies to all entities that have goodwill reported in their financial statements. The standard will be effective for fiscal years beginning after December 15, 2011, with early adoption permitted. We do not intend to adopt the provisions of this standard early.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with our consolidated financial statements and the accompanying notes included in "Item 1. Financial Statements" of this report.

In July 2011, the board of directors of Enbridge Management L.L.C., or Enbridge Management, as delegate of our General Partner, announced a quarterly distribution that reflected a $0.01875 per unit increase over the prior quarterly distribution rate which increased our distribution rate to $2.13 on an annualized basis.

RESULTS OF OPERATIONS—OVERVIEW

We provide services to our customers and returns for our unit holders primarily through the following activities:

- Interstate pipeline transportation and storage of crude oil and liquid petroleum;
- Gathering, treating, processing and transportation of natural gas and natural gas liquids, or NGLs, through pipelines and related facilities; and
- Supply, transportation and sales services, including purchasing and selling natural gas and NGLs.

We conduct our business through three business segments: Liquids, Natural Gas and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

The following table reflects our operating income by business segment and corporate charges for each of the three and nine month periods ended September 30, 2011 and 2010.

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Operating Income (Loss)				
Liquids	$148.4	$(330.9)	$518.8	$ (30.7)
Natural Gas	68.9	17.9	157.6	113.4
Marketing	(1.2)	2.4	(0.4)	5.3
Corporate, operating and administrative	(0.5)	(2.1)	(2.5)	(3.3)
Total Operating Income (Loss)	215.6	(312.7)	673.5	84.7
Interest expense	78.7	70.1	236.6	199.0
Other income (expense)	—	(0.6)	6.0	16.1
Income tax expense	2.1	2.9	5.3	7.5
Net income (loss)	134.8	(386.3)	437.6	(105.7)
Less: Net income attributable to noncontrolling interest	12.2	20.1	41.0	45.3
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$122.6	$(406.4)	$396.6	$(151.0)

Contractual arrangements in our Liquids, Natural Gas and Marketing segments expose us to market risks associated with changes in commodity prices where we receive crude oil, natural gas or NGLs in return for the services we provide or where we purchase natural gas or NGLs. Our unhedged commodity position is fully exposed to fluctuations in commodity prices. These fluctuations can be significant if commodity prices experience significant volatility. We employ derivative financial instruments to hedge a portion of our commodity position and to reduce our exposure to fluctuations in crude oil, natural gas and NGL prices. Some of these derivative financial instruments do not qualify for hedge accounting under the provisions of authoritative accounting guidance, which can create volatility in our earnings that can be significant. However, these fluctuations in earnings do not affect our cash flow. Cash flow is only affected when we settle the derivative instrument.

Summary Analysis of Operating Results

Liquids

The operating income of our Liquids business for the three and nine month periods ended September 30, 2011 increased $479.3 million and $549.5 million from the same periods in 2010, respectively, primarily due to the following:

- The decreases in environmental costs, net of recoveries of $421.5 million and $436.9 million for the three and nine month periods ended September 30, 2011, respectively, as compared to the same periods of 2010;
- Unrealized, non-cash, mark-to-market net gains of $33.7 million and $38.5 million for the three and nine month periods ended September 30, 2011, respectively, associated with derivative financial instruments that do not qualify for hedge accounting treatment compared with $0.3 million of net losses and $0.1 million of net gains we experienced in the respective periods of 2010;
- Higher average daily delivery volumes on all three of our systems when compared to the same period in 2010;
- Transportation rates we implemented July 1, 2011, which increased the index rates on all three of our Liquids systems in connection with the Federal Energy Regulatory Commission, or FERC, increasing the annual change to the Producer Price Index for Finished Goods; and
- $52.2 million we received in the second quarter of 2011 for settlement of a dispute related to oil measurement losses, which we recognized as a reduction to operating expenses.

Natural Gas

The following factors affected the operating income of our Natural Gas business for the three and nine month periods ended September 30, 2011, as compared with the same periods of 2010:

- Unrealized, non-cash, mark-to-market net gains of $15.5 million and $16.0 million for the three and nine month periods ended September 30, 2011, respectively, associated with derivative financial instruments that do not qualify for hedge accounting treatment compared with $15.8 million of net losses and $14.5 million of net gains we experienced in the respective periods of 2010;
- Increased natural gas and NGL volumes on our Anadarko system resulting from continuing production development in the Granite Wash play, coupled with additional volumes associated with the Elk City Natural Gas Gathering and Processing System, referred to as the Elk City system, we acquired in September 2010;
- Volume growth and the related revenue derived from the services provided by our East Texas system resulting from new assets we have placed in service to capture the growing natural gas production from the Haynesville shale formation; and
- Partially offsetting the above are the additional operating costs associated with the Elk City system and the impact of severe winter weather conditions and plant downtime in the first quarter of 2011, which reduced average daily volumes on our East Texas and North Texas systems by approximately 56,000 million of British Thermal Units per day, or MMBtu/d, in the first quarter of 2011, or 18,000 MMBtu/d for the first nine months of 2011.

Marketing

Included in the operating results of our Marketing business for the three and nine month periods ended September 30, 2011 were unrealized, non-cash, mark-to-market, net gains of $1.6 million and net losses of $0.1 million, respectively, associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance. Comparatively, for the three and nine month periods ended September 30, 2010, we experienced $1.3 million of unrealized, non-cash, mark-to-market, net gains and net losses of $3.0 million, respectively. Impacting the changes in fair values of our derivative financial instruments for the three and nine month periods ended September 30, 2011 from the same periods of 2010 are declines in operating income resulting from relatively stable natural gas prices during 2011, which have limited opportunities for us to benefit from price differentials between market centers.

Derivative Transactions and Hedging Activities

We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices and interest rates and to reduce variability in our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and/or forecasted transaction and are not entered into with the objective of speculating on commodity prices or interest rates. We record all derivative instruments in our consolidated financial statements at fair market value pursuant to the requirements of applicable authoritative accounting guidance. We record changes in the fair value of our derivative financial instruments that do not qualify for hedge accounting in our consolidated statements of income as follows:

- Natural Gas and Marketing segments commodity-based derivatives—"Cost of natural gas"
- Liquids segment commodity-based derivatives—"Operating revenue" and "Power"
- Corporate interest rate derivatives—"Interest expense"

The changes in fair value of our derivatives are also presented as a reconciling item on our consolidated statements of cash flows. The following table presents the net unrealized gains and losses associated with the changes in fair value of our derivative financial instruments:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2011	2010	2011	2010
	(in millions)			
Liquids segment				
Non-qualified hedges	$33.7	$ (0.3)	$38.5	$ 0.1
Natural Gas segment				
Hedge ineffectiveness	(1.5)	3.1	(0.1)	4.5
Non-qualified hedges	17.0	(18.9)	16.1	10.0
Marketing				
Non-qualified hedges	1.6	1.3	(0.1)	(3.0)
Commodity derivative fair value net gains (losses)	50.8	(14.8)	54.4	11.6
Corporate				
Non-qualified interest rate hedges	(0.2)	(0.4)	(0.5)	(0.9)
Derivative fair value net gains (losses)	$50.6	$(15.2)	$53.9	$10.7

RESULTS OF OPERATIONS—BY SEGMENT

Liquids

The following tables set forth the operating results and statistics of our Liquids segment assets for the periods presented:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Operating Results				
Operating revenues	$363.0	$ 301.1	$974.7	$882.7
Environmental costs, net of recoveries	56.1	477.6	45.2	482.1
Oil measurement adjustments	(2.8)	(0.2)	(61.5)	(0.2)
Operating and administrative	74.4	59.6	218.5	184.0
Power	37.7	36.7	107.2	105.5
Depreciation and amortization	49.2	48.0	146.5	131.7
Impairment charge	—	10.3	—	10.3
Operating expenses	214.6	632.0	455.9	913.4
Operating Income (Loss)	$148.4	$(330.9)	$518.8	$ (30.7)
Operating Statistics				
Lakehead system:				
United States[(1)]	1,338	1,271	1,313	1,311
Province of Ontario[(1)]	375	326	372	343
Total Lakehead system deliveries[(1)]	1,713	1,597	1,685	1,654
Barrel miles (billions)	114	105	334	329
Average haul (miles)	724	713	726	729
Mid-Continent system deliveries[(1)]	233	215	225	208
North Dakota system:				
Trunkline	203	158	182	158
Gathering	3	6	4	6
Total North Dakota system deliveries[(1)]	206	164	186	164
Total Liquids Segment Delivery Volumes[(1)]	2,152	1,976	2,096	2,026

(1) Average barrels per day in thousands.

Three month period ended September 30, 2011 compared with three month period ended September 30, 2010

The operating revenue of our Liquids business increased for the three month period ended September 30, 2011 when compared with the same period in 2010 partially due to a $33.6 million increase in unrealized, non-cash, mark-to-market net gains related to derivative financial instruments as compared with the same period in 2010. In March 2010, we began to use forward contracts to hedge a portion of the crude oil we expect to receive from our customers as a pipeline loss allowance as part of the transportation of their crude oil. We subsequently sell this crude oil at market rates. We executed derivative financial instruments which fix the sales price we will receive in the future for the sale of this crude oil. We elected not to designate these derivative financial instruments as cash flow hedges.

Further contributing to the increase in operating revenue on our Liquids segment was the higher average daily delivery volumes on all three of our systems when compared to the same period in 2010. The overall increase in average delivery volumes on our systems increased operating revenues by approximately $18.4 million for our Liquids segment. The total average daily deliveries from our liquid systems increased approximately nine percent, to 2.152 million barrels per day, or Bpd, for the three month period ended September 30, 2011 from 1.976 million Bpd for the same period in 2010. The increase in average deliveries on our liquid systems was partly attributable to the operation of Lines 6A and 6B, which were shut down for part of the same period in 2010 due to the Line 6A and Line 6B crude oil releases.

Average daily delivery volumes on our North Dakota system increased 26 percent during the three month period ended September 30, 2011 to 206,000 Bpd from 164,000 Bpd during the same period in 2010. The additional volumes were the result of an increase in capacity on our North Dakota system resulting from the elimination of segregated sour service on the system. The positive increase also reflects volume from the newly completed Portal Reversal Expansion Project, or PREP.

Another contributing factor to the increase in operating revenue was due to transportation rates implemented July 1, 2011, which increased the index rates on all three of our Liquids systems. In May 2011, the FERC determined that the annual change in the Producer Price Index for Finished Goods, or PPI-FG, plus 2.65 percent (PPI-FG+2.65 percent) should be the oil pricing index for the next five years as opposed to PPI-FG+1.30 percent for the same period in 2010. The increase in rates is also due to an increase in the PPI-FG as compared to the same period in 2010. Approximately $4.4 million of the increase in operating revenue for the quarter ended September 30, 2011 when compared to the same period in 2010 is attributable to the higher transportation rates.

The "Operating and administrative" expenses of our Liquids business increased $14.8 million from the three month period ended September 30, 2011 when compared with the same period in 2010 primarily due to the following:

- Higher costs related to our pipeline integrity program;
- Additional workforce related costs associated with the operational, administrative, regulatory and compliance support necessary for our systems;
- Property tax increases associated with assets we constructed and placed in service;
- Higher costs for repair and maintenance activities; and
- Increases in other variable costs incurred in relation to our expanded pipeline systems.

The increase in depreciation expense of $1.2 million is directly attributable to the additional assets we have placed in service since the same period in 2010.

In September 2010, our West Tulsa crude oil pipeline was abandoned due to a significant decrease in throughput on the pipeline and, as a result, we recognized a $10.3 million impairment charge during the third quarter of 2010 to reduce the carrying amount of the asset to zero, as compared to no such impairments in the same period in 2011.

Operating Impact of Lines 6A and 6B Crude Oil Releases

As a result of our response to recent additional work direction from the Environmental Protection Agency, or EPA, additional information concerning the reassessment of the overall monitoring area, related cleanup, including submerged oil recovery operations, and remediation activities, we have revised our total estimate for costs related to the crude oil release on Line 6B of our Lakehead system to $725.0 million, before insurance recoveries, as of September 30, 2011, an increase of $140.0 million from June 30, 2011, as we have previously disclosed. The $140.0 million increase in our estimate includes the estimated costs related to the additional scope of work set forth in our response to the EPA directive we submitted to the EPA on October 20, 2011. We continue to make progress on the cleanup, remediation and restoration of the areas affected by the Line 6B crude oil release. We expect to make payments for additional costs associated with reassessment, remediation and restoration of the area, air and groundwater monitoring, along with other legal, professional and regulatory costs through future periods. All the initiatives we will undertake in the monitoring and restoration phase are intended to restore the crude oil release area to the satisfaction of the appropriate regulatory authorities.

For purposes of estimating our expected losses associated with the Line 6B crude oil release, we have included those costs that we considered probable and that could be reasonably estimated at September 30, 2011. Our estimates do not include amounts we have capitalized or any fines, penalties or claims associated with the release that may later become evident and is before insurance recoveries. Our assumptions include, where applicable, estimates of the expected number of days the associated services will be required and rates that we have obtained from contracts negotiated for the respective service and equipment providers. As we receive invoices for the actual personnel, equipment and services, our estimates will continue to be further refined. Our estimates also consider currently available facts, existing technology and presently enacted laws and regulations. These amounts also consider our and other companies' prior experience remediating contaminated sites and data released by government organizations. Despite the efforts we have made to ensure the reasonableness of our estimates, changes to the recorded amounts associated with this release are possible as more reliable information becomes available. We continue to have the potential of incurring additional costs in connection with this crude oil release due to variations in any or all of the categories described above including modified or revised requirements from regulatory agencies in addition to fines and penalties as well as expenditures associated with litigation and settlement of claims.

We are continuing to monitor the areas affected by the crude oil release from Line 6A of our Lakehead system for any additional requirements. We have substantially completed the cleanup, remediation and restoration of the areas affected by the release.

In connection with this crude oil release, we have not revised our estimate since June 30, 2011 that we will incur aggregate costs of approximately $48.0 million, before insurance recoveries and excluding fines and penalties. We continue to monitor this estimate based upon actual invoices received and paid for the personnel, equipment and services provided by our vendors and currently available facts specific to these circumstances, existing technology and presently enacted laws and regulations to determine if our estimate should be updated.

The claims for the crude oil releases from Lines 6A and 6B are covered by the insurance policy that expired on April 30, 2011, which had an aggregate limit of $650 million for pollution liability. Based on our increased estimate of costs associated with these crude oil releases, Enbridge Inc. or Enbridge, is likely to exceed the limits of its coverage under this insurance policy. We are pursuing recovery of the costs associated with the Line 6A crude oil release from third parties; however, there can be no assurance that any such recovery will be obtained. Additionally, fines and penalties would not be covered under our existing insurance policy.

For the three month period ended September 30, 2011 we recognized a receivable of $85.0 million for insurance recoveries as reductions to "Environmental costs, net of recoveries" for the three month periods ended September 30, 2011. We expect to record a receivable for additional amounts we claim for recovery pursuant to our insurance policies during the period that we deem realization of the claim for recovery to be probable.

During the second quarter of 2011, Enbridge renewed its comprehensive insurance program and the current coverage year has an aggregate limit of $575.0 million for pollution liability for the period May 1, 2011 through April 30, 2012.

The decrease of $421.5 million in environmental expenses, net of recoveries for the three month period ended September 30, 2011 when compared to the same period in 2010 is primarily due to incurring $475.0 million of costs for the Line 6A and Line 6B incidents in the third quarter of 2010 compared to $140 million of cost for these incidents offset by insurance recoveries of $85 million for the three month period ended September 30, 2011.

Nine month period ended September 30, 2011 compared with nine month period ended September 30, 2010

Our Liquids segment contributed $518.8 million of operating income during the nine month period ended September 30, 2011, representing a $549.5 million increase over the $30.7 million operating loss for the same period in 2010. The components comprising the operating income of our Liquids business changed during the nine month period ended September 30, 2011, as compared with the same period in 2010, primarily for the reasons noted above in our three month analysis, in addition to the items discussed below.

For the nine month period ended September 30, 2011, we have recorded $135.0 million for insurance recoveries related to the costs of our Line 6B crude oil release, which increased operating income.

For the nine month period ended September 30, 2011, we settled a dispute with a shipper on our Lakehead crude oil pipeline system, which we recognized in June 2011, for oil measurement adjustments we had previously experienced in prior years. We recorded $52.2 million to "Oil measurement adjustments", which is a reduction to operating expenses, for the nine month period ended September 30, 2011 and there was no such settlement in the same period in 2010.

Future Prospects Update for Liquids

The following discussion provides an update to the status of projects that we and Enbridge are currently developing and should be read in conjunction with the information included in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2010.

Eastern Market Expansion

In October 2011, we and Enbridge announced two projects that will provide increased access to refineries in the United States upper mid-west and in Ontario, Canada for light crude oil produced in western Canada and the United States. One of the projects involves the expansion of our Line 5 light crude line between Superior, Wisconsin and Sarnia, Ontario by 50,000 Bpd, at a total cost of approximately $100 million of which we are obligated for $95 million while Enbridge is obligated for the remaining $5 million. Complementing the Line 5 expansion, Enbridge plans on reversing a portion of its Line 9 in western Ontario to permit crude oil movements eastbound from Sarnia as far as Westover, Ontario. Subject to regulatory approvals, both projects are targeting to be in service in late 2012. The project will enable growing light crude production from the Bakken shale and from Alberta to meet refinery needs in Michigan, Ohio and Ontario. The project provides another much needed transportation outlet for light crude, mitigating the current discounting of supplies in this basin while also providing more favorable supply costs to refiners currently dependent on crudes priced off of the Atlantic basin.

Bakken Pipeline Expansion

In August 2010, we announced the Bakken Project, a joint crude oil pipeline expansion project with an affiliate of Enbridge in the Bakken and Three Forks formations located in the states of Montana and North Dakota and the Canadian provinces of Saskatchewan and Manitoba. The Bakken Project will follow our existing rights of way in the United States and those of Enbridge Income Fund Holdings in Canada to terminate and deliver to the Enbridge Mainline system's terminal at Cromer, Manitoba, Canada. The United States portion of the Bakken Project will expand the United States portion of Line 26 by constructing two new pumping stations in Kenaston and Lignite, North Dakota, and replacing an 11-mile segment of the existing 12-inch diameter pipeline that runs from these two locations. The project also calls for an expansion at our existing terminal and station in Berthold, North Dakota. When completed, the Bakken Project will increase the takeaway capacity from this region by 145,000 Bpd, with further expansion available to increase the takeaway capacity to 325,000 Bpd. The United States portion of the Bakken Project will have an estimated cost of approximately $339 million. We completed a successful binding open season in February 2011 with commitments received for an aggregate of 100,000 Bpd of capacity of the 145,000 Bpd expansion. We commenced construction in July of 2011 with an expected in-service date in the first quarter of 2013.

Bakken Access Program

In October 2011, we announced the Bakken Access Program, a series of projects totaling approximately $90 million, which represent an upstream expansion that will further complement our Bakken expansion, as discussed above. This expansion program will substantially enhance our gathering capabilities on the North Dakota system by 100,000 Bpd. This program is expected to be in service by early 2013, and it involves increasing pipeline capacities, construction of additional storage tanks and addition of truck access facilities at multiple locations in western North Dakota.

Cushing Terminal Storage Expansion Project

During late 2010, we began construction on nine new storage tanks at our Cushing terminal with an approximate shell capacity of 3.2 million barrels. The additional storage tanks will have an estimated cost of $78 million and are expected to be in service by early 2012.

In April 2011, the board of directors of Enbridge Management approved plans to begin construction on four new tanks at our Cushing terminal with an approximate shell capacity of 1.0 million barrels. The new tanks will have an estimated cost of $33 million and are targeted to be in service by December 2012.

Line Replacement Program

On May 12, 2011 we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system at an estimated cost of $286.0 million. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory approvals, the new segments of pipeline will be constructed mostly in 2012 and are targeted to be placed in service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through our Facilities Surcharge Mechanism, or FSM, that is part of the system-wide rates of the Lakehead system. We have subsequently revised the scope of this project to increase the cost by approximately $30.0 million, which will bring the total capital for this replacement program to an estimated cost of $316.0 million. The $30.0 million of additional costs do not currently have recovery under the FSM.

Other Matters

Line 6B Pipeline Integrity Plan

We completed on schedule all the work required by the Pipeline and Hazardous Materials Safety Administration, or PHMSA, that we agreed to perform as part of our restart of Line 6B. Additionally, a new line was installed beneath the St. Clair River in March 2011 and was tied into the existing pipeline during June 2011 and we announced plans for a pipeline replacement program as discussed above. Additional integrity expenditures, which could be significant, may be required after this initial remediation plan. The total cost of these integrity measures is separate from the environmental liabilities discussed above. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with our capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature. We expect to incur ongoing operating costs for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems.

In February 2011, we filed a supplement to our FSM, which became effective on April 1, 2011, for recovery of $175.0 million of capital costs and $5.0 million of operating costs for the 2010 and 2011 Line 6B Pipeline Integrity Plan. The costs associated with the Line 6B Pipeline Integrity Plan, which include an equity return component, interest expense and an allowance for income taxes will be recovered over a 30-year period, while operating costs will be recovered through our annual tolls for actual costs incurred. These costs include costs associated with the PHMSA Corrective Action Order and other required integrity work.

International Joint Toll Agreement

Enbridge Pipelines Inc., or EPI, filed a settlement agreement in May 2011 that is referred to as the Competitive Toll Settlement, or CTS, which was effective on July 1, 2011. On June 24, 2011, the National Energy Board, or NEB, announced its approval the CTS. The CTS includes a provision for a joint tariff for volumes originating in Western Canada that are transported on our Lakehead system. We have entered into an International Joint Tariff Agreement, or IJTA, with EPI that ensures the joint tariff revenues are allocated based on the existing Lakehead rate structures. United States tolls for service on our portion of the Lakehead system will not be affected by the CTS and will continue to be established by our existing toll agreements. We do not expect the terms of the CTS or the IJTA to affect our operating results, cash flows or financial position. The CTS provides a solid platform for the liquids pipeline business to develop new market access points on the mainline by providing shippers with a stable and competitive long-term toll, thereby preserving and enhancing throughput on both the EPI and Lakehead systems.

Natural Gas

The following tables set forth the operating results of our Natural Gas segment assets and approximate average daily volumes of our major systems in MMBtu/d for the periods presented.

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2011	**2010**	**2011**	**2010**
	(unaudited; in millions)			
Operating revenues	$ 1,436.4	$ 996.9	$ 4,384.2	$ 2,870.2
Cost of natural gas	1,233.3	869.1	3,826.8	2,447.7
Environmental costs, net of recoveries	—	—	(0.4)	—
Operating and administrative	104.5	78.3	289.8	215.8
Depreciation and amortization	29.7	31.6	110.4	93.3
Operating expenses	1,367.5	979.0	4,226.6	2,756.8
Operating Income	$ 68.9	$ 17.9	$ 157.6	$ 113.4
Operating Statistics (MMBtu/d)				
East Texas	1,469,000	1,332,000	1,392,000	1,233,000
Anadarko	1,039,000	694,000	1,007,000	618,000
North Texas	333,000	355,000	340,000	354,000
Total[(1)]	2,841,000	2,381,000	2,739,000	2,205,000

(1) Average daily volumes for the three and nine month periods ended September 30, 2011 include 264,000 MMBtu/d and 249,000 MMBtu/d, respectively, of volumes associated with our acquisition of the Elk City system.

Three month period ended September 30, 2011 compared with three month period ended September 30, 2010

The primary factors affecting the operating income of our Natural Gas business for the three month period ended September 30, 2011 as compared with the same period of 2010 are as follows:

- $31.3 million increase in unrealized, non-cash, mark-to-market net gains from derivative instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with the same period of 2010;
- Increased natural gas gathering and processing volumes on our Anadarko system as a result of growth in the Granite Wash play and the additional 264,000 MMBtu/d of volumes associated with our acquisition of the Elk City system in September 2010;

- Increased volumes on our East Texas system due to new assets being placed in service to capture growth associated with Haynesville production;
- Increases in operating and administrative costs associated with our September 2010 Elk City system acquisition and the expansion of our systems; and
- $1.9 million decrease in depreciation expense primarily due to a revision in depreciation rates for the Anadarko, North Texas and East Texas systems effective July 1, 2011, which resulted in a decrease of $8.5 million in depreciation expense. This decrease was partially offset with an increase in depreciation associated with the Elk City system we acquired in September 2010 and additional assets that were put in service during 2010.

Changes in the average forward prices of natural gas, NGLs and condensate from June 30, 2011 to September 30, 2011 produced unrealized, non-cash, mark-to-market net gains of $15.5 million from the non-qualifying commodity derivatives we use to economically hedge a portion of the natural gas, NGLs and condensate resulting from the operating activities of our Natural Gas business. Fractionation margins, representing the relative difference between the price we receive from the sale of NGLs and the corresponding cost of natural gas we purchase for processing, narrowed during the third quarter of 2011 as a result of NGL forward prices decreasing at a higher rate than natural gas forward prices during the same period. This forward pricing environment produced unrealized, non-cash, mark-to-market gains on derivatives we use to hedge the spread between forward prices of natural gas and NGLs.

Comparatively, changes in the average forward prices of natural gas, NGLs and condensate from June 30, 2010 to September 30, 2010, produced unrealized, non-cash, mark-to-market net losses of $15.8 million from the non-qualifying commodity derivatives we use to economically hedge a portion of the natural gas, NGLs and condensate resulting from the operating activities of our Natural Gas business. Fractionation margins widened during the third quarter of 2010 as a result of higher NGL forward prices and lower natural gas forward prices, which produced unrealized, non-cash mark-to-market losses on derivatives hedging fractionation margins.

The following table depicts the effect that unrealized, non-cash, mark-to-market net gains and losses had on the operating results of our Natural Gas segment for the three and nine month periods ended September 30, 2011 and 2010:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Hedge ineffectiveness	$ (1.5)	$ 3.1	$ (0.1)	$ 4.5
Non-qualified hedges	17.0	(18.9)	16.1	10.0
Derivative fair value gains (losses)	$15.5	$(15.8)	$16.0	$14.5

Revenue for our Natural Gas business is derived from the fees or commodities we receive from the gathering, transportation, processing and treating of natural gas and NGLs for our customers. We are exposed to fluctuations in commodity prices in the near term on approximately 30 to 40 percent of the natural gas, NGLs and condensate we expect to receive as compensation for our services. As a result of this unhedged commodity price exposure, our gross margin, representing revenue less cost of natural gas, generally increases when the prices of these commodities are rising and generally decreases when the prices are declining. NGL prices were higher for the three month period ended September 30, 2011 compared to prices in the same period in 2010.

Our volumes and revenues are the result of wellhead supply contracts and drilling activity in the areas served by our Natural Gas business, primarily the Bossier Trend, Barnett Shale, Granite Wash and the Haynesville Shale. During the three month period ended September 30, 2011, natural gas volumes on our systems increased approximately 19 percent, in relation to the same period of 2010, primarily due to production increases in the Granite Wash and new assets being placed in service to capture the growing production from the Haynesville shale play. Volumes on our Anadarko system increased 50 percent for the three month period ended September 30, 2011 compared with the same period in 2010, of which the majority of the increase was associated with the Elk City system we acquired in September 2010.

A variable element of the operating results of our Natural Gas segment is derived from processing natural gas on our systems. Under percentage of liquids, or POL, contracts, we are required to pay producers a contractually fixed recovery of NGLs regardless of the NGLs we physically produce or our ability to process the NGLs from the natural gas stream. NGLs that are produced in excess of this contractual obligation in addition to the barrels that we produce under traditional keep-whole gas processing arrangements we refer to collectively as keep-whole earnings. Operating revenue less the cost of natural gas derived from keep-whole earnings for the three month period ended September 30, 2011 was $12.0 million, representing a decrease of $2.8 million from the $14.8 million we produced for the same period in 2010.

The reduction in keep-whole earnings is a result of the increasing production of liquids rich natural gas on our Anadarko system, excluding the Elk City acquisition, where a significant number of our contracts are POL type arrangements. This earnings decrease is largely attributable to paying natural gas producers for liquids we are unable to recover due to gas volume increasing faster than our available capacity. The rapid increase in supply is exceeding our existing processing capacity as evidenced by the 12 percent increase in average daily volumes from 694,000 MMBtu/d to 775,000 MMBtu/d on the system for the three months ended September 30, 2011 compared to the same period last year. We are constructing facilities to increase the available processing capacity on both our Anadarko and Elk City systems, which we expect to increase incrementally throughout the year. The most significant of these facilities is the Allison plant, which we expect will be in service prior to the end of 2011.

Operating and administrative costs of our Natural Gas segment were $26.2 million higher for the three month period ended September 30, 2011 compared to the same period in 2010, primarily due to the expansion of our systems, including the Elk City system we acquired in September 2010 and a common carrier trucking company we acquired in October 2010.

Nine month period ended September 30, 2011 compared with nine month period ended September 30, 2010

The primary factors affecting the operating income of our Natural Gas business for the nine month period ended September 30, 2011 as compared with the same period of 2010 are the same as noted in our three-month analysis in addition to the factors discussed below.

Changes in the average forward prices of natural gas, NGLs and condensate from December 31, 2010 to September 30, 2011 produced unrealized, non-cash, mark-to-market net gains of $16.0 million from the non-qualifying commodity derivatives we use to economically hedge a portion of the natural gas, NGLs and condensate in our Natural Gas business, which was an increase of $1.5 million compared to the same period in 2010. During the first nine months of 2010 hedges of our natural gas length significantly increased in value due to sharp declines in forward natural gas prices, which generated net gains of $27.8 million more in 2010 than in the same period of 2011. Offsetting the change in our natural gas length was approximately $29.3 million less in gains in 2010 than in the same nine month period of 2011 related to unrealized NGL and fractionation hedge gains.

Although volumes were higher on the majority of our systems for the nine month period ended September 30, 2011 compared with the same period of 2010, for the reasons discussed in the three-month analysis, in February uncharacteristically cold weather and freezing precipitation moved through Oklahoma and north Texas with temperatures dropping below freezing for extended periods, thus creating mechanical issues with our producers' equipment and their ability to flow natural gas. Producers shut in significant volumes during this period, which reduced the average daily volumes on our systems by approximately 56,000 MMBtu/d for the first quarter 2011. Additionally, mechanical problems on two of our plants required that they be taken out of service for extended periods during the first quarter of 2011 to correct these conditions. The adverse weather conditions and plant downtime had an approximate $13 million negative impact to the gross margin of our Natural Gas business for the nine month period ended September 30, 2011.

Future Prospects for Natural Gas

We intend to expand our natural gas gathering and processing services through internal growth projects designed to provide exposure to incremental supplies of natural gas at the wellhead, increase opportunities to serve additional customers, including new wholesale customers, and allow expansion of our treating and processing businesses. Additionally, we will pursue acquisitions to expand our natural gas services in situations where we have natural advantages to create additional value for our existing assets.

Texas Express Pipeline

In September 2011, we announced a joint venture between us, Enterprise Products Partners L.P., or Enterprise Products, and Anadarko Petroleum Corporation, or Anadarko, to design and construct a new NGL pipeline referred to as the Texas Express Pipeline, or TEP. TEP will be owned 45 percent by Enterprise Products, 35 percent by us and 20 percent by Anadarko. Our portion of the estimated costs is $385 million. The pipeline will originate at Skellytown, Texas and extend approximately 580 miles to NGL fractionation and storage facilities in Mont Belvieu, Texas. The pipeline will have an initial capacity of approximately 280,000 Bpd and will be readily expandable to approximately 400,000 Bpd.

In addition, the joint venture will include two new NGL gathering systems. The first will connect TEP to natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and Western Oklahoma. The second NGL gathering system will connect the new pipeline to central Texas, Barnett Shale processing plants. Volumes from the Rockies, Permian Basin and Mid-Continent regions will be delivered to the TEP system utilizing Enterprise's existing Mid-America Pipeline assets between the Conway hub and Enterprise's Hobbs NGL fractionation facility in Gaines County, Texas. Enterprise will construct and serve as the operator of the pipeline, while we will build and operate the new gathering systems. The pipeline and portions of the gathering systems are expected to begin service in the second quarter of 2013, subject to regulatory approvals.

TEP will serve as a link between growing supply sources of NGLs in the Anadarko region and the primary end use market on the United States Gulf Coast and will be providing guaranteed NGL access to the primary United States petrochemical market located in Mont Belvieu. TEP will assist us in fulfilling our strategic objective of expanding our presence in the natural gas and NGL value chain and provide a new source of strong and stable cash flow.

Allison Cryogenic Processing Plant

In April 2010, we announced plans to construct a cryogenic processing plant and other facilities on our Anadarko system, which we refer to as the Allison Plant. The Allison Plant will have a planned capacity of 150 MMcf/d and is intended to accommodate the acceleration of horizontal drilling activity that exists in the Granite Wash formation in the Texas Panhandle, where our Anadarko system is located. The Allison Plant is anticipated to be in service prior to the end of 2011.

Ajax Cryogenic Processing Plant

In August 2011, we announced plans to construct an additional processing plant and other facilities on our Anadarko system at a cost of $230 million, which we refer to as our Ajax Plant. The Ajax Plant will have a planned capacity of 150 MMcf/d and is intended to meet the continued strength of horizontal drilling activity in this area. The Ajax Plant is anticipated to be in service in early 2013.

The Allison and Ajax plants, when operational, will increase the total processing capacity on our Anadarko system to approximately 1,200 MMcf/d.

South Haynesville Shale Expansion

In February 2010, we announced plans to expand our East Texas system by constructing three lateral pipelines into the East Texas portion of the Haynesville shale, together with a large diameter lateral pipeline from Shelby County to Carthage which will further expand our recently completed Shelby County Loop. The expansion into the Haynesville shale area is expected to increase the capacity of our East Texas system by 900 million cubic feet per day, or MMcf/d. Commitments from natural gas producers in the form of demand payments, acreage dedications and other contractual structures were more than sufficient to proceed with the project. We completed construction of a portion of the pipeline for the project during the second quarter of 2010 and the main trunkline to Carthage in December 2010 and we expect construction of the facilities will continue through the fourth quarter of 2011. Future compression will be layered in, as needed, after the completion of the facilities.

In April 2011, we announced plans to invest an additional $175 million to expand our East Texas system. We have signed long-term agreements with four major natural gas producers along the Texas side of the Haynesville shale to provide gathering, treating and transmission services in Shelby, San Augustine and Nacogdoches counties. The projects involve construction of gathering and related market outlet pipelines and related treating facilities in the Texas Haynesville shale.

Marketing

The following table sets forth the operating results of our Marketing segment assets for the periods presented:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Operating revenues	$572.8	$591.3	$1,674.2	$1,815.0
Cost of natural gas	572.1	586.5	1,669.4	1,802.5
Operating and administrative	1.9	2.3	5.2	7.0
Depreciation and amortization	—	0.1	—	0.2
Operating expenses	574.0	588.9	1,674.6	1,809.7
Operating income (loss)	$ (1.2)	$ 2.4	$ (0.4)	$ 5.3

A majority of the operating income and loss of our Marketing segment is derived from buying natural gas from producers on our Natural Gas segment assets and selling to wholesale customers downstream of our Natural Gas segment assets. Our Natural Gas segment assets provide our Marketing business with access to multiple downstream natural gas pipelines. The Marketing business has purchased long-term transportation and storage rights on multiple interstate and intrastate pipelines, which it can use to transport natural gas to primary markets where it can be sold at more favorable prices.

Three month period ended September 30, 2011 compared with three month period ended September 30, 2010

Included in the operating results of our Marketing segment for the three month period ended September 30, 2011 were unrealized, non-cash, mark-to-market net gains of $1.6 million associated with derivative financial instruments that do not qualify for hedge accounting treatment under authoritative accounting guidance, as compared with the $1.3 million of unrealized non-cash, mark-to-market net gains, for the same period in 2010. For the three month period ended September 30, 2011, the non-cash, mark-to-market, net gains primarily related to our financial instruments that we use to hedge our storage positions. The net gains associated with our storage derivative instruments resulted from the narrowing difference between the natural gas injection price paid to purchase and store natural gas and the withdrawal price at which the natural gas is sold from storage. The non-cash, mark-to-market, net gains for the three month period ended September 30, 2010 was also primarily related to our financial instruments that we use to hedge our storage positions for the same reason noted above.

Offsetting our unrealized, non-cash, mark-to-market net gains for the current period and contributing to the operating loss of our Marketing business were relatively stable natural gas prices during the three month period ended September 30, 2011, which limited opportunities to benefit from significant price differentials between market centers.

Operating income for the three month period ended September 30, 2011 was also negatively affected by non-cash charges of $1.2 million we recorded to reduce the cost basis of our natural gas inventory to net realizable value. Similar charges did not occur in the comparable period of 2010. We expect that a majority of these charges will be recouped when the physical natural gas inventory is sold.

Nine month period ended September 30, 2011 compared with nine month period ended September 30, 2010

The components comprising our operating income changed during the nine month period ended September 30, 2011 compared to the same period in 2010 primarily for the same reasons as in the three month analysis, in addition to the items noted below.

During the nine month period ended September 30, 2011, we had $0.1 million of non-cash, mark-to-market, net losses compared to $3.0 million of unrealized, mark-to-market, net losses for the same period in 2010. The non-cash, mark-to-market, net losses that resulted during the nine month period ended September 30, 2010 resulted from widening differences between forward natural gas purchase and sales prices between market centers, which negatively impacted the values of derivative financial instruments we use to hedge our transportation positions.

Affiliates of our General Partner charge us the costs associated with employees and related benefits for personnel who are assigned to us or otherwise provide us with managerial and administrative services. We have experienced a decrease in workforce related costs for the nine month period ended September 30, 2011 when compared to the same period in 2010, which has contributed to our lower operating and administrative expenses for the 2011 period. Additionally, our operating and administrative expenses were reduced for the nine month period ended September 30, 2011 when compared to the same period in 2010 due to our establishment of a bad debt reserve for a customer in 2010 with no similar reserve being established during 2011.

Corporate

Our interest cost for the three and nine month periods ended September 30, 2011 and 2010 is comprised of the following:

	For the three month period ended September 30,		For the nine month period ended September 30,	
	2011	2010	2011	2010
	(unaudited; in millions)			
Interest expense	$ 78.7	$ 70.1	$236.6	$199.0
Interest capitalized	3.8	1.5	7.5	7.1
Interest cost incurred	$ 82.5	$ 71.6	$244.1	$206.1
Weighted average interest rate	*6.3%*	*6.5%*	*6.4%*	*6.5%*

Three month period ended September 30, 2011 compared with three month period ended September 30, 2010

The increase in interest expense between the three month periods ended September 30, 2011 and 2010 is primarily the result of a higher weighted average outstanding debt balance during the three month period ended September 30, 2011 as compared with the same period in 2010. The increased weighted average outstanding debt balance was primarily a result of the following:

- An increase in our weighted average balance of commercial paper outstanding for the three month period ended September 30, 2011 compared to the same period in 2010; and
- The issuance and sale in September 2010 of $400 million of our 5.50% senior unsecured notes due 2040.

Nine month period ended September 30, 2011 compared with nine month period ended September 30, 2010

The results for corporate activities for the nine month period ended September 30, 2011 compared to the same period in 2010, changed for the same reasons as noted in the three-month analysis above.

Other Matters

Alberta Clipper Pipeline Joint Funding Arrangement and Regulatory Accounting

In July 2009, we entered into a joint funding arrangement to finance construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge including our General Partner. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010. In connection with the joint funding arrangement, we allocated earnings derived from operating the Alberta Clipper Pipeline in the amounts of $12.2 million and $41.0 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Pipeline for the three and nine month periods ended September 30, 2011. We allocated $20.1 million and $45.3 million for the same three and nine month periods ended September 30, 2010. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Proceeds from Claim Settlements

We received proceeds of $11.6 million for settlement of claims we made for payment from unrelated parties in connection with operational matters that occurred in the normal course of business. We recorded $5.6 million as a reduction to "Operating and administrative" expenses of our Liquids segment and $6.0 million as "Other income" in our consolidated statements of income for the nine month period ended September 30, 2011 for the amounts we received in April 2011.

LIQUIDITY AND CAPITAL RESOURCES

Available Liquidity

As set forth in the following table, we had in excess of $1.9 billion of liquidity available to us at September 30, 2011 to meet our ongoing operational, investment and financing needs, as well as the funding requirements associated with the environmental costs resulting from the crude oil releases on Lines 6A and 6B.

	(unaudited; in millions)
Cash and cash equivalents	$ 443.7
Total credit available under New Credit Facility	2,000.0
Less: Amounts outstanding under New Credit Facility	—
Principal amount of commercial paper issuances	375.0
Letters of credit outstanding	124.5
Total	$1,944.2

If the holders of our $500 million in aggregate principal amount, 9.875% Senior Notes due 2019 require us to repay the notes on March 1, 2012, we expect to finance any amounts we are required to repay through borrowings from our new credit agreement with Bank of America, as administrative agent, entered into in September 2011, which we refer to as our New Credit Facility.

General

Our primary operating cash requirements consist of normal operating expenses, core maintenance expenditures, distributions to our partners and payments associated with our risk management activities. We expect to fund our current and future short-term cash requirements for these items from our operating cash flows supplemented as necessary by issuances of commercial paper and borrowings on our New Credit Facility. Margin requirements associated with our derivative transactions are generally supported by letters of credit issued under our New Credit Facility.

Our current business strategy emphasizes developing and expanding our existing Liquids and Natural Gas businesses through targeted acquisitions and organic growth. We expect to initially fund our long-term cash requirements for expansion projects and acquisitions, as well as, retire our maturing and callable debt, first from operating cash flows and then from issuances of commercial paper and borrowings on our New Credit Facility. Likewise, we anticipate initially retiring our maturing debt with similar borrowings on our New Credit Facility. We expect to obtain permanent financing as needed through the issuance of additional equity and debt securities, which we will use to repay amounts initially drawn to fund these activities, although there can be no assurance that such financings will be available on favorable terms, if at all.

Capital Resources

Equity and Debt Securities

Execution of our growth strategy and completion of our planned construction projects contemplate our accessing the public and private equity and credit markets to obtain the capital necessary to fund these activities. We have issued a balanced combination of debt and equity securities to fund our expansion projects and acquisitions. Our internal growth projects and targeted acquisitions may require additional permanent capital and require us to bear the cost of constructing and acquiring assets before we begin to realize a return on them. If market conditions change and capital markets again become constrained, our ability and willingness to complete future debt and equity offerings may be limited. The timing of any future debt and equity offerings will depend on various factors, including prevailing market conditions, interest rates, our financial condition and our credit rating at the time.

Equity Distribution Agreement

In June 2010, we entered into an Equity Distribution Agreement, or EDA, for the issuance and sale from time to time of our Class A common units up to an aggregate amount of $150.0 million. The EDA allowed us to issue and sell our Class A common units at prices we deemed appropriate for our Class A common units. Under the EDA, we sold 2,118,025 Class A common units, representing 4,236,050 units after giving effect to a two-for-one split of our Class A common units that became effective on April 21, 2011, for aggregate gross proceeds of $124.8 million, of which $64.5 million are gross proceeds received in 2011. No further sales will be made under that agreement. On May 27, 2011, we de-registered the remaining aggregate $25.2 million of Class A common units that were registered for sale under the EDA and remained unsold as of that date.

On May 27, 2011, the Partnership entered into an Amended and Restated Equity Distribution Agreement, or Amended EDA, for the issuance and sale from time to time of our Class A common units up to an aggregate amount of $500.0 million from the execution date of the agreement through May 20, 2014. The units issued under the Amended EDA are in addition to the units offered and sold under the EDA. The issuance and sale of our Class A common units, pursuant to the Amended EDA, may be conducted on any day that is a trading day for the New York Stock Exchange.

The following table presents the net proceeds from our Class A common unit issuances, pursuant to the Amended EDA, during the nine month period ended September 30, 2011:

Issuance Date	Number of Class A common units Issued	Average Offering Price per Class A common unit	Net Proceeds to the Partnership(1)	General Partner Contribution(2)	Net Proceeds Including General Partner Contribution
	(unaudited; in millions, except units and per unit amounts)				
May 27 to June 30, 2011	333,794	$30.30	$ 9.9	$0.2	$10.1
July 1 to September 30, 2011	751,766	28.38	20.8	0.4	21.2
	1,085,560		$30.7	$0.6	$31.3

(1) Net of commissions and issuance costs of $0.4 million and $0.6 million for the three and nine month periods ended September 30, 2011.
(2) Contributions made by the General Partner to maintain its two percent general partner interest.

Issuance of Class A Common Units

The following table presents the net proceeds from our Class A common unit issuances for the current year other than pursuant to the EDA and the Amended EDA described above. The proceeds from the September 2011 offering will be used to fund a portion of our capital expansion projects, while the proceeds from the July offering were used to repay a portion of our outstanding commercial paper.

2011 Issuance Date	Number of Class A common units Issued	Offering Price per Class A common unit	Net Proceeds to the Partnership(1)	General Partner Contribution(2)	Net Proceeds Including General Partner Contribution
	(in millions, except units and per unit amount)				
September	8,000,000	$28.20	$218.3	$4.6	$222.9
July	8,050,000	$30.00	$233.7	$4.9	$238.6
2011 Totals	16,050,000		$452.0	$9.5	$461.5

(1) Net of underwriters' fees and discounts, commissions and issuance expenses if any.
(2) Contributions made by the General Partner to maintain its two percent general partner interest.

Available Credit

Our two primary sources of liquidity are provided by our commercial paper program and our New Credit Facility. We have a $1.5 billion commercial paper program that is supported by our New Credit Facility, which we access primarily to provide temporary financing for our operating activities, capital expenditures and acquisitions when the interest rates available to us for commercial paper are more favorable than the rates available under our New Credit Facility.

Credit Facility

In September 2011, we entered into a new credit agreement with Bank of America, as administrative agent, which we refer to as the New Credit Facility. The new agreement is a committed senior unsecured revolving credit facility that permits aggregate borrowings of up to, at any one time outstanding, $2 billion, a letter of credit subfacility and a swing line subfacility with a maturity date of September 26, 2016.

The New Credit Facility replaces the previously existing credit facilities of $1,167.5 million and $600 million with Bank of America and Royal Bank of Canada, as administrative agents, respectively.

The amounts we may borrow under the terms of our New Credit Facility are reduced by the face amount of our letters of credit outstanding. It is our policy to maintain availability at any time under our New Credit Facility that is at least equal to the amount of commercial paper that we have outstanding at such time. Taking that policy into account, at September 30, 2011, we could borrow $1,500.5 million under the terms of our New Credit Facility, determined as follows:

	(in millions)
Total credit available under New Credit Facility	$2,000.0
Less: Amounts outstanding under New Credit Facility	—
Principal amount of commercial paper outstanding	375.0
Letters of credit outstanding	124.5
Total amount we could borrow at September 30, 2011	$1,500.5

Individual London Inter-Bank Offered Rate, or LIBOR rate, borrowings under the terms of our New Credit Facility may be renewed as LIBOR rate borrowings or as base rate borrowings at the end of each LIBOR rate interest period, which is typically a period of three months or less. These renewals do not constitute new borrowings under the New Credit Facility and do not require any cash repayments or prepayments. For the nine month period ended September 30, 2010, we renewed LIBOR rate borrowings of $915.0 million, on a non-cash basis.

Effective September 30, 2011, our New Credit Facility was amended to further modify the definition of Consolidated Earnings Before Income Taxes Depreciation and Amortization, or Consolidated EBITDA, as set forth in the terms of our New Credit Facility, to increase from $550 million to $650 million, the aggregate amount of the costs associated with the crude oil releases on Lines 6A and 6B that are excluded from the computation of Consolidated EBITDA. Specifically, the costs allowed to be excluded from Consolidated EBITDA are those for emergency response, environmental remediation, cleanup activities, costs to repair the pipelines, inspection costs, potential claims by third parties and lost revenue. At September 30, 2011 we were in compliance with the terms of our financial covenants.

Commercial Paper

At September 30, 2011, we had $375.0 million of commercial paper outstanding at a weighted average interest rate of 0.40%, excluding the effect of our interest rate hedging activities. Under our commercial paper program, we had net borrowings of approximately $509.8 million during the nine month period ended September 30, 2011, which include gross issuances of $10,317.9 million and gross repayments of $10,827.7 million. Our policy is that the commercial paper we can issue is limited by the amounts available under our New Credit Facility up to an aggregate principal amount of $1.5 billion. Our commercial paper program was increased from $1.0 billion in August 2011.

Senior Notes due 2021 and 2040

In September 2011, we issued and sold $600 million in aggregate principal amount of senior notes due 2021, which we refer to as the 2021 Notes. The 2021 Notes bear interest at the rate of 4.20% per year and will mature on September 15, 2021. Interest on the 2021 Notes is payable on March 15 and September 15 of each year, beginning on March 15, 2012.

Also in September 2011, we issued and sold an additional $150 million in aggregate principal amount of our 5.50% notes due in 2040, which we refer to as the 2040 Notes. The additional 2040 Notes will be fully fungible with, rank equally in right of payment with and form a part of the same series as the existing 2040 Notes, originally issued by us in September 2010, for all purposes under the governing indenture.

We received net proceeds from the note offerings in September 2011 of approximately $740.7 million after payment of underwriting discounts and commissions and our estimated offering expenses. We used the net proceeds from these offerings to repay a portion of our outstanding commercial paper, to fund a portion of our capital expansion projects and for general corporate purposes.

Joint Funding Arrangement for Alberta Clipper Pipeline

In July 2009, we entered into a joint funding arrangement to finance construction of the United States segment of the Alberta Clipper Pipeline with several of our affiliates and affiliates of Enbridge. The Alberta Clipper Pipeline was mechanically complete in March 2010 and was ready for service on April 1, 2010.

In March 2010, we refinanced $324.6 million of amounts we had outstanding and payable to our General Partner under the A1 Credit Agreement by issuing a promissory note payable to our General Partner, at which time we also terminated the A1 Credit Agreement. The promissory note payable, which we refer to as the A1 Term Note, matures on March 15, 2020, bears interest at a fixed rate of 5.20% and has a maximum loan amount of $400 million. The terms of the A1 Term Note are similar to the terms of our 5.20% senior notes due 2020, except that the A1 Term Note has recourse only to the assets of the United States portion of the Alberta Clipper Pipeline. Under the terms of the A1 Term Note, we have the ability to increase the principal amount outstanding to finance the debt portion of the investment our General Partner is obligated to make pursuant to the Alberta Clipper Joint Funding Arrangement to finance any additional costs associated with the construction of our portion of the Alberta Clipper Pipeline we incur after the date the original A1 Term Note was issued. The increases we make to the principal balance of the A1 Term Note will also mature on March 15, 2020. At September 30, 2011, we had approximately $342.0 million outstanding under the A1 Term Note.

Our General Partner also made equity contributions totaling $3.3 million and $96.6 million to the Enbridge Energy Limited Partnership, or OLP, during the nine month periods ended September 30, 2011 and 2010, to fund its equity portion of the construction costs associated with the Alberta Clipper Pipeline. The OLP paid a distribution of $17.7 million and $61.1 million to our General Partner and its affiliate during the three and nine month periods ended September 30, 2011 for their noncontrolling interest in the Series AC, representing limited partner ownership interests of the OLP that are specifically related to the assets, liabilities and operations of the Alberta Clipper Pipeline.

We allocated earnings derived from operating the Alberta Clipper Pipeline in the amounts of $12.2 million and $41.0 million to our General Partner for its 66.67 percent share of the earnings of the Alberta Clipper Pipeline for the three and nine month periods ended September 30, 2011, respectively. We allocated $20.1 million and $45.3 million for the same three and nine month periods ended September 30, 2010, respectively. We have presented the amounts we allocated to our General Partner for its share of the earnings of the Alberta Clipper Pipeline in "Net income attributable to noncontrolling interest" on our consolidated statements of income.

Cash Requirements

Capital Spending

We expect to make additional expenditures during the remainder of the year for the acquisition and construction of natural gas processing and crude oil transportation infrastructure. In 2011, we expect to spend approximately $1,100 million on system enhancements and other projects associated with our liquids and natural gas systems with the expectation of realizing additional cash flows as projects are completed and placed into service. Of this amount, we made capital expenditures of $755.8 million in the nine month period ended September 30, 2011. At September 30, 2011, we had approximately $309.3 million in outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as property, plant and equipment during 2011.

Lines 6A and 6B Crude Oil Releases

During the nine month period ended September 30, 2011, our cash flows were adversely affected by the approximate $196.5 million we paid for the environmental remediation, restoration and cleanup activities, excluding insurance recoveries, resulting from the crude oil releases that occurred in 2010 on Lines 6A and 6B of our Lakehead system. We anticipate that we will have paid approximately 80 to 90 percent of the total costs associated with these releases by the end of 2011.

Acquisitions

We continue to assess ways to generate value for our unit holders, including reviewing opportunities that may lead to acquisitions or other strategic transactions, some of which may be material. We evaluate opportunities against operational, strategic and financial benchmarks before pursuing them. We expect to pursue potential acquisitions with a focus on natural gas pipelines, NGL pipelines, refined products pipelines, terminals and related facilities. We will seek opportunities for accretive acquisitions throughout the United States, particularly in the United States Gulf Coast area, where we anticipate making asset acquisitions in and around our existing Natural Gas business. We expect to obtain the funds needed to make acquisitions through a combination of cash flows from operating activities, borrowings under our New Credit Facility and the issuance of additional debt and equity securities. All acquisitions are considered in the context of the practical financing constraints presented by the capital markets.

Forecasted Expenditures

We categorize our capital expenditures as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of our existing assets and includes the replacement of system components and equipment which are worn, obsolete or completing its useful life. We also include a portion of our expenditures for connecting natural gas wells, or well-connects, to our natural gas gathering systems as core maintenance expenditures. Enhancement expenditures include our capital expansion projects and other projects that improve the service capability of our existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues and enable us to respond to governmental regulations and developing industry standards.

We estimate our capital expenditures based upon our strategic operating and growth plans, which are also dependent upon our ability to produce or otherwise obtain the financing necessary to accomplish our growth objectives. The following table sets forth our estimates of capital expenditures we expect to make for system enhancement and core maintenance for the year ending December 31, 2011. Although we anticipate making these expenditures in 2011, these estimates may change due to factors beyond our control, including weather-related issues, construction timing, changes in supplier prices or poor economic conditions, which may adversely affect our ability to access the capital markets. Additionally, our estimates may also change as a result of decisions made at a later date to revise the scope of a project or undertake a particular capital program or an acquisition of assets. We made capital expenditures of $755.8 million, including $69.6 million on core maintenance activities, for the nine month period ended September 30, 2011. For the full year ending December 31, 2011, we anticipate our capital expenditures to approximate the following:

	Total Forecasted Expenditures
	(unaudited; in millions)
System enhancements	$ 250
Liquids integrity program	350
Core maintenance activities	100
Haynesville projects	100
North Dakota Expansion Program	90
Allison Related Expansion Capital	140
Cushing Storage	70
	$1,100

We maintain a comprehensive integrity management program for our pipeline systems, which relies on the latest technologies that include internal pipeline inspection tools. These internal pipeline inspection tools identify internal and external corrosion, dents, cracking, stress corrosion cracking and combinations of these conditions. We regularly assess the integrity of our pipelines utilizing the latest generations of metal loss, caliper and crack detection internal pipeline inspection tools. We also conduct hydrostatic testing to determine the integrity of our pipeline systems. Accordingly, we incur substantial expenditures each year for our integrity management programs.

Under our capitalization policy, expenditures that replace major components of property or extend the useful lives of existing assets are capital in nature, while expenditures to inspect and test our pipelines are usually considered operating expenses. The capital components of our programs have increased over time as our pipeline systems age.

On May 12, 2011 we announced plans to replace 75-miles of non-contiguous sections of Line 6B of our Lakehead system at an estimated cost of $286 million. Our Line 6B pipeline runs from Griffith, Indiana through Michigan to the international border at the St. Clair River. Subject to regulatory approvals, the new segments of pipeline will be constructed mostly in 2012 and are targeted to be placed in-service by the first quarter of 2013 in consultation with, and to minimize impact to, refiners and shippers served by Line 6B crude oil deliveries. These costs will be recovered through the FSM that is part of the system-wide rates of the Lakehead system. We have recently revised the scope of this project to increase the cost by approximately $30 million, which will bring the total capital for this replacement program to an estimated cost of $316 million. The $30 million of additional costs do not currently have recovery under the FSM.

Additional integrity expenditures, which could be significant, may be required after this initial remediation program. The total cost of these integrity measures is separate from the environmental liabilities discussed above. The pipeline integrity and replacement costs will be capitalized or expensed in accordance with our capitalization policies as these costs are incurred, the majority of which are expected to be capital in nature.

In February 2011, we included in the supplement to our FSM, to be effective April 1, 2011, recovery of $175 million of capital costs and $5 million of operating costs for the 2010 and 2011 Line 6B Pipeline Integrity Plan. The costs associated with the Line 6B Pipeline Integrity Plan, which include an equity return component, interest expense and an allowance for income taxes, will be recovered over a 30 year period, while operating costs will be recovered through our annual tolls for actual costs incurred. These costs include costs associated with the PHMSA Corrective Action Order and other required integrity work.

We expect to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of our pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection, maintenance and capital replacement. We also anticipate that core maintenance capital will continue to increase due to the growth of our pipeline systems and the aging of portions of these systems. Core maintenance expenditures are expected to be funded by operating cash flows.

We anticipate funding system enhancement capital expenditures temporarily through borrowing under the terms of our New Credit Facility, with permanent debt and equity funding being obtained when appropriate.

Derivative Activities

We use derivative instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the volatility of our cash flows and manage the risks associated with market fluctuations in commodity prices and interest rates. Based on our risk management policies, all of our derivative instruments are employed in connection with an underlying asset, liability or anticipated transaction and are not entered into with the objective of speculating on commodity prices or interest rates.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding commodity derivative financial instruments based upon the market values at September 30, 2011 for each of the indicated calendar years:

	Notional	2011	2012	2013	2014	2015	2016	Total [4]
		(unaudited; dollars, in millions)						
Swaps								
Natural gas[1]	133,398,717	$ 0.2	$ (0.9)	$ 4.2	$ 0.1	$ —	$—	$ 3.6
NGL[2]	5,492,963	(14.9)	(4.3)	(3.2)	1.1	1.3	—	(20.0)
Crude[2]	5,583,339	(0.6)	13.8	14.1	11.5	10.0	0.5	49.3
Options								
Natural gas—puts purchased[1]	92,000	—	—	—	—	—	—	—
Natural gas—calls written[1]	92,000	—	—	—	—	—	—	—
NGL—puts purchased[2]	773,678	0.4	5.1	—	—	—	—	5.5
Crude—puts purchased[2]	54,740	0.7	—	—	—	—	—	0.7
Forward contracts								
Crude[2]	1,203,720	1.5	—	—	—	—	—	1.5
Natural gas[1]	42,746,277	0.4	1.0	0.4	0.1	0.1	0.1	2.1
NGL[2]	9,294,650	4.7	3.0	0.3	—	—	—	8.0
Power[3]	182,351	(0.2)	(0.3)	(0.1)	(0.2)	—	—	(0.8)
Totals		$ (7.8)	$17.4	$15.7	$12.6	$11.4	$ 0.6	$ 49.9

(1) Notional amounts for natural gas are recorded in millions of British thermal units, or MMBtu.

(2) Notional amounts for NGL and crude are recorded in Barrels, or Bbl.

(3) Notional amounts for power are recorded in Megawatt hours, or MWh.

(4) Fair values exclude credit adjustments of approximately $3.5 million of losses at September 30, 2011.

The following table provides summarized information about the timing and expected settlement amounts of our outstanding interest rate derivative instruments at September 30, 2011 for each of the indicated calendar years:

	Notional Amount	2011	2012	2013	2014	2015	Thereafter	Total [1]
		(unaudited; dollars in millions)						
Interest Rate Derivatives								
Interest Rate Swaps:								
Floating to Fixed	$1,025.0	$(5.7)	$ (27.2)	$(23.4)	$ (3.8)	$(0.2)	$—	$ (60.3)
Fixed to Floating	$ 125.0	1.0	5.4	2.7	—	—	—	9.1
Pre-issuance hedges	$1,650.0	—	(114.0)	(49.6)	(12.1)	—	—	(175.7)
		$(4.7)	$(135.8)	$(70.3)	$(15.9)	$(0.2)	$—	$(226.9)

(1) Fair values are presented in millions of dollars and exclude credit adjustments of approximately $18.9 million of gains at September 30, 2011.

Cash Flow Analysis

The following table summarizes the changes in cash flows by operating, investing and financing for each of the periods indicated:

	For the nine month period ended September 30, 2011	2010	Variance 2011 vs. 2010 Increase (Decrease)
	(unaudited; in millions)		
Total cash provided by (used in):			
Operating activities	$ 652.6	$ 411.8	$ 240.8
Investing activities	(660.8)	(1,241.4)	580.6
Financing activities	307.0	892.6	(585.6)
Net increase in cash and cash equivalents	298.8	63.0	235.8
Cash and cash equivalents at beginning of year	144.9	143.6	1.3
Cash and cash equivalents at end of period	$ 443.7	$ 206.6	$ 237.1

Operating Activities

Net cash provided by our operating activities increased $240.8 million for the nine month period ended September 30, 2011 compared with the same period in 2010 primarily due to higher changes in our working capital accounts for the nine month period ended September 30, 2011 compared to the same period of 2010 coupled with general timing differences in the collection on and payment of our current and related party accounts. The changes in working capital accounts for the nine month period ended September 30, 2011 were also affected by $198.7 million of environmental costs paid, which included $196.5 million of costs associated with the Lines 6A and 6B crude oil releases, offset by $135.0 million of environmental insurance recoveries associated with the Line 6B crude oil release, as compared with, $147.3 million of environmental costs paid and no similar recoveries in the same period of 2010.

Investing Activities

Net cash used in our investing activities during the nine month period ended September 30, 2011 decreased by $580.6 million compared to the same period of 2010 primarily due to additional acquisitions in 2010. We spent an additional $676.4 million on asset acquisitions, represented primarily by the Elk City acquisition of $686.1 million, in 2010 when compared to the same period in 2011.

Financing Activities

The net cash used in our financing activities decreased $585.6 million during the nine month period ended September 30, 2011 compared to the same period in 2010 primarily due to the following:

	(unaudited; in millions)
Net proceeds related to Class A common units issued in 2011 compared to 2010[(1)]	$ 505.4
Increase in distributions to our partners in 2011 compared to 2010	(55.8)
Decrease in net affiliate borrowings in 2011 compared to 2010[(2)]	(78.4)
Net proceeds from senior notes issued in 2011 compared to 2010	(149.8)
Net repayments on our credit facilities in 2010 compared to 2011	438.0
Net repayments on our commercial paper in 2011 compared to 2010	(1,104.6)
Decrease in capital contributions from our General Partner and its affiliate for its ownership interest in the Alberta Clipper Pipeline	(93.3)
Distributions to our General Partner and its affiliate for its ownership interest in the Alberta Clipper Pipeline paid in 2011 compared to no distributions in 2010	(43.9)
Other	(3.2)
	$ (585.6)

(1) Includes $11.5 million of contributions from the General Partner to maintain its two percent interest.

(2) For the nine month period ended September 30, 2010, we borrowed $403.7 million from our General Partner which we used to repay $330.7 million we borrowed on the A1 Credit Facility and to fund $79.1 million of additional costs incurred for the construction of the Alberta Clipper Pipeline. During the same period in 2011, we borrowed only $7.0 million and repaid $12.4 million to our General Partner and affiliates.

SUBSEQUENT EVENTS

Distribution to Partners

On October 28, 2011, the board of directors of Enbridge Management declared a distribution payable to our partners on November 14, 2011. The distribution will be paid to unit holders of record as of November 4, 2011, of our available cash of $173.2 million at September 30, 2011, or $0.53250 per limited partner unit. Of this distribution, $153.1 million will be paid in cash, $19.7 million will be distributed in i-units to our i-unitholder and $0.4 million will be retained from our General Partner in respect of the i-unit distribution to maintain its two percent general partner interest.

Distribution to Series AC Interests

On October 28, 2011, the board of directors of Enbridge Management, acting on behalf of Enbridge Pipelines (Lakehead) L.L.C., the managing general partner of the OLP and the Series AC, declared a distribution payable to the holders of the Series AC general and limited partner interests. The OLP will pay $15.3 million to the noncontrolling interest in the Series AC, while $7.7 million will be paid to us.

REGULATORY MATTERS

FERC Transportation Tariffs

Effective April 1, 2011, we filed our annual tariff rate adjustment with the FERC to reflect true-ups for the difference between estimated and actual cost and throughput data for the prior year and our projected costs and throughput for 2011 related to our expansion projects. Also included was a supplement to our FSM for recovery of the costs related to the 2010 and 2011 Line 6B Integrity Program, including costs associated with the PHMSA Corrective Action Order and as discussed in Note 9—*Commitments and Contingencies—Pipeline Integrity Commitment*. The FSM, which was approved in July 2004, is a component of our Lakehead system's overall rate structure and allows for the recovery of costs for enhancements or modifications to our Lakehead system.

This tariff filing decreased the average transportation rate for crude oil movements from the Canadian border to Chicago, Illinois by approximately $0.21 per barrel, to an average of approximately $1.76 per barrel. The surcharge is applicable to each barrel of crude oil that is placed on our system beginning on the effective date of the tariff, which we recognize as revenue when the barrels are delivered, typically a period of approximately 30 days from the date shipped.

On May 2, 2011, we filed FERC Tariff 45.0.0 to establish International Joint Tariff rates applicable to the transportation of petroleum from all receipt points in Western Canada on Enbridge Pipelines Inc., or EPI's, Canadian Mainline system to all delivery points on the Lakehead pipeline system owned by the OLP and delivery points on the Canadian mainline located downstream of the Lakehead system. This tariff filing became effective July 1, 2011.

Effective July 1, 2011, we increased the rates for transportation on our Lakehead, North Dakota and Ozark systems in compliance with the indexed rate ceilings allowed by the FERC. In May 2011, the FERC determined that the annual change in the Producer Price Index for Finished Goods, or PPI-FG, plus 2.65 percent (PPI-FG + 2.65 percent) should be the oil pricing index for the five year period ending July 2016. The index is used to establish rate ceiling levels for oil pipeline rate changes. The increase in rates is due to a increase in the Producer Price Index for Finished Goods as compared with prior periods. For our Lakehead system, indexing applies only to the base rates and does not apply to the SEP II, Terrace and Facilities surcharges, which include the Southern Access Pipeline and Alberta Clipper Project.

RECENT ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

Accounting Standards Update—Fair Value Measurement

In May 2011, the Financial Accounting Standards Board, or FASB, issued an amendment to the guidance on fair value measurement as part of the FASB's joint project with the International Accounting Standards Board, or IASB, to achieve common fair value measurement and disclosure requirements in United States generally accepted accounting principles, or GAAP, and International Financial Reporting Standards, or IFRS. The key changes relevant to our business include enhanced disclosures requiring additional information about unobservable inputs and valuation methods utilized and requiring the fair value hierarchy level of assets and liabilities not recorded at fair value but where fair value disclosure is required.

The accounting update is effective for the first reporting period beginning after December 15, 2011, with early application prohibited. The guidance will require prospective application. The adoption of this pronouncement is not anticipated to have a material impact on our financial statements.

Accounting Standards Update—Presentation of Comprehensive Income

In June 2011, the FASB issued guidance on the presentation of comprehensive income as part of the FASB's joint project with the IASB, requiring presentation of net income and other comprehensive income either in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive, statements of net income and other comprehensive income. The guidance eliminated the option to report other comprehensive income and its components in the statement of changes in equity and the disclosure of reclassification adjustments in the footnotes. The guidance does not change which components of comprehensive income are recognized in net income or other comprehensive income, when an item of other comprehensive income must be reclassified to net income or the earnings-per-share computation.

The accounting update is effective for the first reporting period beginning after December 15, 2011, with early application permitted. The guidance requires retrospective application. We do not intend to adopt the provisions of this pronouncement early. Our adoption of this pronouncement will require us to modify the items we present in the consolidated statements of comprehensive income

Accounting Standards Update—Testing Goodwill for Impairment

In September 2011, the FASB issued Accounting Standard No. 2011-08, *Testing Goodwill for Impairment,* which is intended to reduce the overall costs and the complexity of impairment testing. The standard allows an entity to first assess qualitative factors to determine whether it is necessary to perform the current two-step goodwill impairment test. An entity no longer will be required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. The standard does not change the current two-step test and applies to all entities that have goodwill reported in their financial statements. The standard will be effective for fiscal years beginning after December 15, 2011, with early adoption permitted. We do not intend to adopt the provisions of this standard early.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following should be read in conjunction with the information presented in our Annual Report on Form 10-K for the year ended December 31, 2010, in addition to information presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. There have been no material changes to that information other than as presented below.

Our net income and cash flows are subject to volatility stemming from changes in interest rates on our variable rate debt obligations and fluctuations in commodity prices of natural gas, NGLs, condensate and fractionation margins, which is the relative difference between the price we receive from NGL sales and the corresponding cost of natural gas purchases. Our interest rate risk exposure does not exist within any of our segments, but exists at the corporate level where our fixed and variable rate debt obligations are issued. Our exposure to commodity price risk exists within each of our segments. We use derivative financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to manage the risks associated with market fluctuations in commodity prices and interest rates, as well as to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are employed in connection with an underlying asset, liability and forecasted transaction and are not entered into with the objective of speculating on interest rates or commodity prices.

Interest Rate Derivatives

The table below provides information about our derivative financial instruments that we use to hedge the interest payments on our variable rate debt obligations that are sensitive to changes in interest rates and to lock in the interest rate on anticipated issuances of debt in the future. For interest rate swaps, the table presents notional amounts, the rates charged on the underlying notional amounts and weighted average interest rates paid by expected maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract. Weighted average variable rates are based on implied forward rates in the yield curve at September 30, 2011.

Date of Maturity & Contract Type	Accounting Treatment	Notional	Average Fixed Rate[1]	Fair Value[2] September 30, 2011	Fair Value[2] December 31, 2010
	(dollars in millions)				
Contracts maturing in 2013					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$600	4.15%	$ (48.0)	$(51.8)
Interest Rate Swaps—Pay Fixed	Non-qualifying	$125	4.35%	$ (8.3)	$(10.7)
Interest Rate Swaps—Pay Float	Non-qualifying	$125	4.75%	$ 9.1	$ 11.9
Contracts maturing in 2015					
Interest Rate Swaps—Pay Fixed	Cash Flow Hedge	$300	2.43%	$ (4.0)	$ 1.9
Contracts settling prior to maturity					
2011—Pre-issuance Hedges[3]	Cash Flow Hedge	$300	2.92%	$ —	$ 23.4
2012—Pre-issuance Hedges	Cash Flow Hedge	$600	4.56%	$(114.0)	$(13.7)
2013—Pre-issuance Hedges	Cash Flow Hedge	$300	4.62%	$ (49.6)	$ (0.3)
2014—Pre-issuance Hedges	Cash Flow Hedge	$750	3.15%	$ (12.1)	$ —

(1) Interest rate derivative contracts are based on the one-month or three-month London Inter-Bank Offered Rate, or LIBOR.

(2) The fair value is determined from quoted market prices at September 30, 2011 and December 31, 2010, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $18.9 million of gains at September 30, 2011 and $0.5 million of gains at December 31, 2010.

(3) Settled in connection with the issuance of our 2021 Notes.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity based swaps and physical contracts at September 30, 2011 and December 31, 2010.

	At September 30, 2011						At December 31, 2010	
			Wtd. Average Price(2)		Fair Value(3)		Fair Value(3)	
	Commodity	Notional(1)	Receive	Pay	Asset	Liability	Asset	Liability
Portion of contracts maturing in 2011								
Swaps								
Receive variable/pay fixed	Natural Gas	3,197,234	$ 3.76	$ 4.51	$ —	$ (2.4)	$ 0.4	$ (4.9)
	NGL	34,762	$87.47	$49.58	$ 1.3	$ —	$ 6.8	$ —
	Crude Oil	90,000	$79.29	$90.71	$ —	$ (1.0)	$ 0.4	$ —
Receive fixed/pay variable	Natural Gas	4,904,397	$ 4.13	$ 3.78	$ 2.1	$ (0.3)	$ 2.6	$ (6.7)
	NGL	1,330,088	$51.73	$63.94	$ 2.6	$(18.8)	$ 5.0	$(38.8)
	Crude Oil	467,568	$79.78	$78.81	$ 2.0	$ (1.6)	$—	$(22.9)
Receive variable/pay variable	Natural Gas	24,661,617	$ 3.72	$ 3.68	$ 1.4	$ (0.6)	$ 5.0	$ (1.2)
Physical Contracts								
Receive fixed/pay variable	NGL	2,028,798	$76.95	$74.14	$ 6.2	$ (0.5)	$ 0.5	$ (4.4)
	Crude Oil	219,067	$89.88	$79.38	$ 2.3	$ —	$—	$ (1.9)
Receive variable/pay fixed	NGL	1,665,026	$74.02	$76.08	$ 0.4	$ (3.8)	$ 1.6	$ —
	Crude Oil	159,700	$79.33	$87.66	$ —	$ (1.3)	$ 1.1	$ —
Pay fixed	Power(4)	18,489	$30.86	$44.36	$ —	$ (0.2)	$—	$ (0.8)
Receive variable/pay variable	Crude Oil	824,953	$80.13	$79.42	$ 2.3	$ (1.8)	$ 0.5	$ (0.2)
	NGL	2,492,120	$71.63	$70.67	$ 5.9	$ (3.5)	$ 6.2	$ (1.4)
	Natural Gas	11,143,979	$ 3.73	$ 3.69	$ 0.4	$ —	$ 1.1	$ —
Portion of contracts maturing in 2012								
Swaps								
Receive variable/pay fixed	Natural Gas	2,362,813	$ 4.13	$ 6.40	$ —	$ (5.3)	$—	$ (3.8)
	NGL	91,500	$16.65	$16.80	$ —	$ —	$—	$ —
Receive fixed/pay variable	Natural Gas	4,864,120	$ 4.78	$ 4.13	$ 3.8	$ (0.7)	$ 1.7	$ (2.1)
	NGL	2,551,428	$54.00	$55.68	$ 9.0	$(13.3)	$ 8.0	$ (7.6)
	Crude Oil	1,455,216	$88.79	$79.30	$15.8	$ (2.0)	$—	$(10.7)
Receive variable/pay variable	Natural Gas	54,914,000	$ 4.17	$ 4.15	$ 2.1	$ (0.8)	$ 1.0	$ (0.8)
Physical Contracts								
Receive variable/pay fixed	NGL	25,000	$76.91	$72.39	$ 0.1	$ —	$—	$ —
Receive fixed/pay variable	NGL	230,791	$79.25	$77.09	$ 0.7	$ (0.2)	$—	$ —
Receive variable/pay variable	Natural Gas	20,780,946	$ 4.18	$ 4.13	$ 1.0	$ —	$ 0.6	$ —
	NGL	2,531,486	$63.69	$62.74	$ 6.4	$ (4.0)	$ 0.7	$ —
Pay fixed	Power(4)	62,330	$35.74	$40.29	$ —	$ (0.3)	$—	$ —
Portion of contracts maturing in 2013								
Swaps								
Receive variable/pay fixed	Natural Gas	93,066	$ 4.72	$ 5.19	$ —	$ —	$—	$ —
Receive fixed/pay variable	Natural Gas	1,009,600	$ 8.41	$ 4.69	$ 3.7	$ —	$ 3.3	$ —
	NGL	994,260	$64.86	$68.09	$ 1.3	$ (4.5)	$ 0.3	$ (3.2)
	Crude Oil	1,430,435	$93.38	$83.42	$16.2	$ (2.1)	$ 2.2	$ (7.4)
Receive variable/pay variable	Natural Gas	31,070,000	$ 4.76	$ 4.74	$ 0.6	$ (0.1)	$ 0.1	$ (0.2)
Physical Contracts								
Receive variable/pay variable	Natural Gas	7,845,782	$ 4.79	$ 4.73	$ 0.4	$ —	$ 0.2	$ —
	NGL	321,429	$52.68	$51.59	$ 0.3	$ —	$—	$ —
Pay fixed	Power(4)	42,924	$40.15	$42.86	$ —	$ (0.1)	$—	$ —
Portion of contracts maturing in 2014								
Swaps								
Receive variable/pay fixed	Natural Gas	21,870	$ 5.13	$ 5.22	$ —	$ —	$—	$ —
Receive fixed/pay variable	NGL	381,425	$77.58	$74.59	$ 1.8	$ (0.7)	$—	$ (1.1)
	Crude Oil	1,228,955	$94.27	$84.71	$11.6	$ (0.1)	$—	$ (2.8)
Receive variable/pay variable	Natural Gas	6,300,000	$ 5.18	$ 5.17	$ 0.1	$ —	$—	$ (0.1)
Physical Contracts								
Receive variable/pay variable	Natural Gas	1,115,075	$ 5.29	$ 5.17	$ 0.1	$ —	$—	$ —
Pay fixed	Power(4)	58,608	$43.47	$46.58	$ —	$ (0.2)	$—	$ —
Portion of contracts maturing in 2015								
Swaps								
Receive fixed/pay variable	Crude Oil	865,415	$97.72	$85.74	$10.0	$ —	$—	$ (0.7)
	NGL	109,500	$88.36	$76.26	$ 1.3	$ —	$—	$ (0.1)
Physical Contracts								
Receive variable/pay variable	Natural Gas	1,115,075	$ 5.52	$ 5.39	$ 0.1	$ —	$—	$ —
Portion of contracts maturing in 2016								
Swaps								
Receive fixed/pay variable	Crude Oil	45,750	$99.31	$86.78	$ 0.5	$ —	$—	$ —
Physical Contracts								
Receive variable/pay variable	Natural Gas	745,420	$ 5.74	$ 5.61	$ 0.1	$ —	$—	$ —

(1) Volumes of natural gas are measured in millions of British Thermal Units, or MMBtu, whereas volumes of NGL and crude oil are measured in barrels, or Bbl. Our power purchase agreements are measured in Megawatt hours, or MWh.
(2) Weighted average prices received and paid are in $/MMBtu for natural gas, $/Bbl for NGL and crude oil and $/MWh for power.
(3) The fair value is determined based on quoted market prices at September 30, 2011 and December 31, 2010, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $3.4 million of losses and $0.6 million of gains at September 30, 2011 and December 31, 2010, respectively.
(4) For physical power, the receive price shown represents the index price used for valuation purposes.

The following table provides summarized information about the fair values of expected cash flows of our outstanding commodity options at September 30, 2011 and December 31, 2010.

	At September 30, 2011						At December 31, 2010	
					Fair Value[3]		Fair Value[3]	
	Commodity	Notional[1]	Strike Price[2]	Market Price[2]	Asset	Liability	Asset	Liability
Portion of option contracts maturing in 2011								
Calls (written)	Natural Gas[4]	92,000	$ 4.31	$ 3.81	$—	$—	$—	$(0.2)
Puts (purchased)	Natural Gas[4]	92,000	$ 3.40	$ 3.81	$—	$—	$—	$—
	NGL	159,896	$54.79	$65.59	$ 0.4	$—	$ 3.6	$—
	Crude Oil	54,740	$88.65	$79.37	$ 0.7	$—	$ 1.3	$—
Portion of option contracts maturing in 2012								
Puts (purchased)	NGL	613,782	$44.85	$45.31	$ 5.1	$—	$ 3.9	$—

(1) Volumes of natural gas are measured in MMBtu, whereas volumes of NGL and crude oil are measured in Bbl.
(2) Strike and market prices are in $/MMBtu for natural gas and in $/Bbl for NGL and crude oil.
(3) The fair value is determined based on quoted market prices at September 30, 2011 and December 31, 2010, respectively, discounted using the swap rate for the respective periods to consider the time value of money. Fair values are presented in millions of dollars and exclude credit valuation adjustments of approximately $0.1 million of losses at September 30, 2011 and $0.1 million of losses at December 31, 2010.
(4) Indicates transactions which, in combination, create a collar, representing a floor and ceiling on the price and provide long-term price protection.

Our credit exposure for over-the-counter derivatives is directly with our counterparty and continues until the maturity or termination of the contract. When appropriate, valuations are adjusted for various factors such as credit and liquidity considerations.

The table below summarizes our derivative balances by counterparty credit quality (negative amounts represent our net obligations to pay the counterparty).

	September 30, 2011	December 31, 2010
	(in millions)	
Counterparty Credit Quality*		
AAA	$ (0.1)	$ —
AA	(114.8)	(48.7)
A	(55.7)	(61.3)
Lower than A	9.0	5.8
	$(161.6)	$(104.2)

* As determined by nationally-recognized statistical ratings organizations.

Item 4. Controls and Procedures

We and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that we are able to record, process, summarize and report the information required to be disclosed in our annual and quarterly reports under the Securities Exchange Act of 1934, as amended, referred to as the Exchange Act, within the time periods specified in the rules and forms of the Securities and Exchange Commission. These disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive and principal financial officers, as appropriate, to allow timely decisions regarding required disclosure. Our management, with the participation of our principal executive and principal financial officers, has evaluated the effectiveness of our disclosure controls and procedures as of September 30, 2011. Based upon that evaluation, our principal executive and principal financial officers concluded that our disclosure controls and procedures are effective to accomplish their purpose. In conducting this assessment, our management relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on our behalf. We have not made any changes that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting during the three month period ended September 30, 2011.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

Refer to Part I, Item 1. Financial statements, Note 9—*Commitments and Contingencies,* which is incorporated herein by reference.

Item 1A. Risk Factors

There have been no material changes to risk factors as previously disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2010.

Item 6. Exhibits

Reference is made to the "Index of Exhibits" following the signature page, which we hereby incorporate into this Item.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C.
as delegate of
Enbridge Energy Company, Inc.
as General Partner

Date: October 31, 2011

By: /S/ MARK A. MAKI
Mark A. Maki
President
(Principal Executive Officer)

Date: October 31, 2011

By: /S/ STEPHEN J. NEYLAND
Stephen J. Neyland
Vice President, Finance
(Principal Financial Officer)

Index of Exhibits

Each exhibit identified below is filed as a part of this Quarterly Report on Form 10-Q. Exhibits included in this filing are designated by an asterisk; all exhibits not so designated are incorporated by reference to a prior filing as indicated.

Exhibit Number	Description
4.1	Twelfth Supplemental Indenture, dated September 15, 2011, between the Partnership, as Issuer, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 of the Partnership's Current Report on Form 8-K, filed on September 15, 2011).
10.1	Credit Agreement, dated as of September 26, 2011, by and among the Partnership, the lenders from time to time parties thereto, Bank of America, N.A., as Administrative Agent, Swing Line Lender and L/C Issuer and Royal Bank of Canada as a L/C Issuer (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K, filed on September 29, 2011).
31.1*	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Principal Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.